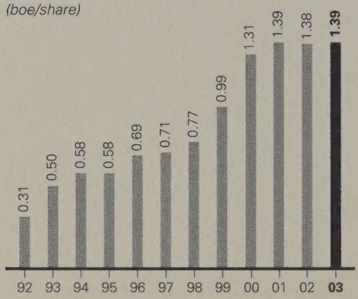
2003

Zargon

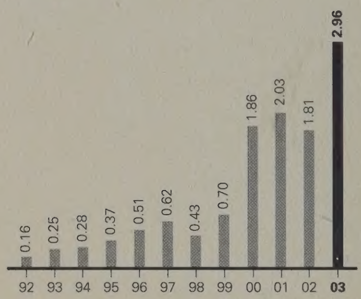
ANNUAL REPORT

PROVED AND PROBABLE RESERVES PER SHARE
(boe/share)

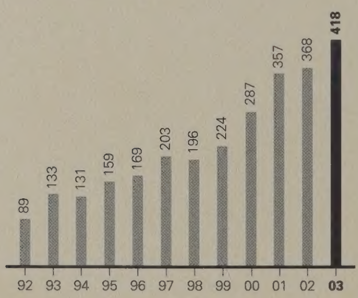


The prior years (1992—2002) established (proved plus 50 percent probable) reserves have been used as comparison to December 31, 2003 proved and probable reserves so as to reflect the equivalent level of risk applied to the 2003 reserves as defined by the NI 51-101 guidelines.

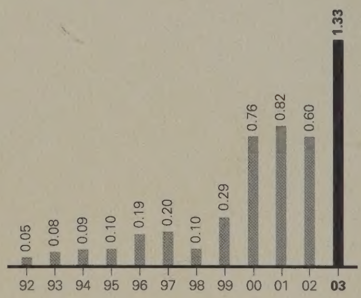
CASH FLOW PER SHARE
($/share—diluted)



PRODUCTION PER SHARE
(boe/d per million shares)



EARNINGS PER SHARE
($/share—diluted)



CORPORATE PROFILE

Zargon Oil & Gas Ltd. is a junior oil and natural gas exploration, development and production company operating in the Canadian provinces of Alberta, Saskatchewan and Manitoba and in the US states of North Dakota and Montana. Throughout its twelve-year history, Zargon has adhered to a disciplined, "value seeking" opportunistic approach based on the exploration of natural gas prospective undeveloped lands and the exploitation of existing oil pools. This technically focused approach has delivered 48 consecutive quarters of positive earnings (41 quarters as a public company), a weighted average annual return on equity in excess of 18 percent per year, and a per share compounded proved and probable reserve and production growth rate of 15 percent per year. With resource inventories of 398 thousand net acres of undeveloped land available for natural gas exploration and 152 million barrels of working interest oil-in-place available for oil exploitation, Zargon is particularly well positioned this year to provide profitable growth from its existing assets. Zargon's common shares trade on the Toronto Stock Exchange under the symbol "ZAR."

	2003	2002	Percent Change
FINANCIAL ($ million, except per share amounts)			
Income and Investments			
Petroleum and natural gas revenue	**101.66**	65.54	55
Cash flow from operations	**54.35**	32.12	69
Net earnings	**24.53**	10.68	130
Net capital expenditures	**39.91**	35.55	12
Balance Sheet at Year End			
Property and equipment, net	**161.91**	141.01	15
Bank indebtedness	**6.98**	25.28	(72)
Shareholders' equity	**112.59**	86.60	30
Common shares outstanding (million)	**17.99**	17.64	2
Per Common Share, Diluted			
Cash flow from operations ($/share)	**2.96**	1.81	64
Net earnings ($/share)	**1.33**	0.60	122
OPERATING			
Average Daily Production			
Oil and liquids (bbl/d)	**3,287**	2,968	11
Natural gas (mmcf/d)	**24.95**	20.29	23
Equivalent (boe/d)	**7,446**	6,349	17
Equivalent per million shares (boe/d)	**418**	368	14
Average Selling Price (before hedges)			
Oil and liquids ($/bbl)	**36.66**	34.45	6
Natural gas ($/mcf)	**6.33**	3.81	66
Proved and Probable Reserves (year end)			
Oil and liquids (mmbbl)	**13.57**	12.45	9
Natural gas (bcf)	**68.58**	71.21	(4)
Equivalent (mmboe)	**24.99**	24.31	3
Equivalent per share—year end (boe)	**1.39**	1.38	1
Wells Drilled, Net	**38.6**	31.6	22
Undeveloped Land (thousand net acres)	**398**	331	20

Notes:

- *Throughout this report, the calculation of barrels of equivalent (boe) is based on the conversion ratio that six thousand cubic feet of natural gas is equivalent to one barrel of oil.*
- *Average daily production per million shares uses the weighted average number of shares for the period.*
- *Cash flow from operations is a non-GAAP term that represents net earnings for non-cash items. For a further discussion about this term refer to page 29 of the report.*
- *The December 31, 2002 established (proved plus 50 percent probable) reserves have been used as comparison to December 31, 2003 proved and probable reserves so as to reflect the equivalent level of risk applied to the 2003 reserves as defined by the NI 51-101 guidelines.*

Zargon reported excellent financial results in 2003. Revenue, cash flow and earnings increased 55, 69 and 130 percent, respectively, over the prior year.

THE YEAR IN BRIEF

Zargon reported excellent progress in 2003 with record financial results. Commodity prices were high throughout the year and production volumes showed strong gains. Natural gas production increased 23 percent and oil and liquids production increased 11 percent over the prior year. Compared to 2002, revenue increased 55 percent to $101.7 million, cash flow from operations rose 69 percent to $54.3 million ($2.96 per diluted share) and net earnings rose 130 percent to $24.5 million ($1.33 per diluted share), the latter helped by changes in federal tax legislation. The undeveloped land inventory continued to grow in 2003, reaching 398 thousand net acres at year end. During the year, Zargon concluded a $39.91 million capital program that was highlighted by West Central Alberta natural gas exploration successes. The year's strong cash flows fully funded this capital program and provided a surplus $14.44 million that was used to pay down corporate debt.

CORPORATE STRATEGIES

Since 1992, Zargon has created value by following a well-defined opportunistic strategic plan that has consistently delivered efficient reserve and production growth. Two distinct, complementary skills have facilitated Zargon's growth: the efficient exploitation of oil properties, and the seismically driven exploration for natural gas. Our oil exploitation business begins with the identification and acquisition of properties with a large underdeveloped oil-in-place. We then deploy improved recovery techniques or geologically driven exploitation concepts to develop additional reserves. Through numerous property and corporate acquisitions over our history, Zargon has assembled a working interest inventory of 152 million barrels of exploitable oil-in-place primarily located in our Williston Basin core area.

Our natural gas exploration business explores for shallow and medium depth natural gas reservoirs based on seismic, geological, and occasionally reservoir engineering concepts. Our strategy is to acquire large contiguous land blocks with multi-zone potential and reduce exploration risk by applying advanced seismic and detailed geological mapping. The resource inputs for our natural gas exploration business are seismically or geologically prospective undeveloped lands, preferably in areas where we control natural gas facilities.

ZARGON MANAGEMENT TEAM

LEFT TO RIGHT: **SHEILA WARES, DAN ROULSTON, JOHN McCUTCHEON, YVES GAUTHIER, CRAIG HANSEN, KEN YOUNG, MARK LAKE**

Through the purchase at Crown sales of large amounts of undeveloped land, we have expanded our natural gas exploration and development activities from primarily the Alberta Plains to selected areas of West Central Alberta, including Highvale, Pembina and the Peace River Arch. The expansion has been successful; by the 2003 year end undeveloped land in West Central Alberta had increased to 174 thousand net acres and natural gas production had climbed to more than 10 million cubic feet per day. Overall, Zargon's total undeveloped land inventory grew by 20 percent in 2003 to almost 400 thousand net acres at year end.

To accomplish our history of profitable growth, Zargon has developed the skills and financial discipline to manage and allocate capital effectively. We believe that the appropriate time to build the feedstocks of our business, namely the undeveloped natural gas prospective land and the underexploited large oil-in-place properties, is when commodity prices are low and our industry's enthusiasm is muted. Zargon's significant oil-in-place resource base was built through property acquisitions in the late 1990s and with the 2001 Herc Oil Corp. acquisition. Similarly, our undeveloped natural gas prospective land base was assembled with the 2002 Hadrian Energy Corp. acquisition and during 2002 and early 2003 when Crown land prices were substantially lower. During the current period of historically high commodity prices and an extremely confident Canadian

Capital expenditures of $39.91 million were internally funded and total corporate debt was reduced by 54 percent to $13.09 million.

Compared to 2002, Zargon's successful West Central Alberta natural gas exploration initiatives had delivered more than eight million cubic feet per day of incremental production by the 2003 fourth quarter.

marketplace, we find the costs of acquiring new oil-in-place properties and undeveloped natural gas lands to be expensive. Consequently, we have shifted our resource-gathering focus to geologically similar but less expensive opportunities in the United States where significant oil exploitation opportunities in northern North Dakota and large natural gas prospective undeveloped land blocks in northern Montana can be assembled at reasonable cost.

2003 KEY ACHIEVEMENTS

Zargon delivered strong, exploration-based production growth accompanied by record financial results in 2003. As planned, the 2003 exploration effort was focused on our new and expanding West Central Alberta natural gas initiative. Our exploration results were very good, as evidenced by substantial natural gas production additions in each of the West Central Alberta core exploration areas of Highvale, Pembina and the Peace River Arch.

The 2003 growth of the key West Central Alberta natural gas exploration area is demonstrated by the following parameters:

- The undeveloped land inventory increased 59 percent to 174 thousand net acres.
- A total of 17.8 net wells were drilled in 2003 up from 12.8 net wells in 2002.
- Natural gas production increased 215 percent to 7.27 million cubic feet per day in 2003, with the fourth quarter rate climbing to 10.45 million cubic feet per day.
- Land and seismic weighted capital expenditures of $15.55 million delivered proved and probable reserves (NI 51-101 standard excluding revisions) of 1.54 million barrels of equivalent.

Calendar 2004 promises to be an exciting year for the West Central Alberta core area with two new Peace River Arch discoveries to be developed, new Pembina shallow gas wells to be tied-in and many interesting exploration concepts to be tested at the Peace River Arch, Highvale, Pembina and the geologically related north Montana properties.

At our Alberta Plains properties, Zargon was successful in maintaining steady production throughout the year with only a moderate level of field activity. In 2003, 12.8 net wells were drilled that provided proved and probable reserves (NI 51-101 standard excluding revisions) of 0.92 million barrels of equivalent. In 2003 the Alberta Plains properties generated $31.17 million of property cash flow of which $9.27 million was reinvested in the same properties to maintain production at levels consistent with the prior year's rates. With resources of over 185 thousand net acres of undeveloped natural gas prospective land, primarily in the Jarrow and Hamilton Lake properties, and 12 million barrels of exploitable working interest oil-in-place at Taber, we anticipate that the Alberta Plains core area will deliver stable production volumes with only moderate capital expenditures for some time to come.

2003 OPERATING HIGHLIGHTS

Capital expenditures in 2003 totalled $39.91 million, with $37.30 million allocated to exploration and development activities. Operating highlights included:

- Driven by West Central Alberta exploration successes, natural gas production grew 23 percent to 24.95 million cubic feet per day. By the fourth quarter natural gas production had increased to 28.03 million cubic feet per day.
- Oil and liquids production increased 11 percent to 3,287 barrels per day.
- After application of the more conservative NI 51-101 standards of disclosure for reserve estimates, proved and probable reserves increased by three percent to 24.99 million barrels of equivalent.
- Zargon's undeveloped land inventory increased by 20 percent to 398 thousand net acres.
- Zargon drilled a 38.6 net well program with an 84 percent success rate that delivered 24.6 net natural gas wells and 8.0 net oil wells.

2003 FINANCIAL HIGHLIGHTS

Much higher natural gas prices plus continuing strong oil prices in 2003 enabled Zargon to establish record levels of revenue, cash flow and net earnings.

- Zargon's field commodity prices climbed substantially in 2003 with oil prices increasing six percent to $36.66 per barrel and natural gas prices increasing 66 percent to $6.33 per thousand cubic feet.
- Cash flow from operations climbed 69 percent to $54.35 million. Cash flow per share increased 64 percent to $2.96 per diluted share.
- Earnings climbed 130 percent to $24.53 million. Earnings per share increased 122 percent to $1.33 per diluted share.
- Through a series of dispositions of higher cost properties and by successful field cost containment programs, Zargon's 2003 average field operating cost was reduced by six percent to $6.33 per barrel of equivalent.
- Zargon's after-tax return on equity averaged 25 percent in 2003.
- The year's strong cash flows fully funded an efficient $39.91 million capital program and provided a surplus $14.44 million that was used to pay down corporate debt. The current net debt represents less than fourth quarter 2003 cash flow.

Zargon had good success with the important Williston Basin oil exploitation core area in 2003, delivering a 14 percent gain in production to 2,449 barrels of equivalent per day by spending 88 percent of the core area's property cash flow. The year's $15.09 million capital program provided proved and probable reserves (NI 51-101 standard excluding revisions) of 2.02 million barrels of equivalent. A highlight in the year was the $4.95 million acquisition of the Truro Unit in Renville County, North Dakota. Also, a total of 8.0 net wells were drilled, five separate 3D seismic surveys were shot, and reservoir re-pressurization through water injections was implemented at three projects. These activities are part of a measured multi-year exploitation program that provides efficient reserve additions and a stable platform of oil production. With a working interest oil-in-place of over 130 million barrels in 14 separate projects, we anticipate steady exploitation-driven production growth from the Williston Basin for the foreseeable future.

Zargon's 398 thousand net acres of undeveloped land and 152 million barrels of working interest oil-in-place provide the resource inputs to deliver profitable and efficient natural gas exploration and oil exploitation programs for many years to come.

Consistent with our long-term value-seeking strategy, Zargon sold five minor properties in 2003 for an aggregate $5.22 million to take advantage of the very robust property market. The properties were generally high cost and were of little strategic value to Zargon. With these sales and the similar 2002 property dispositions, Zargon was able to upgrade the focus and character of its property base. Furthermore, the sales were instrumental in permitting Zargon to deliver a six percent annual reduction in per unit operating costs, during a time when the industry in general is experiencing severe upward operating cost trends.

The year ended December 31, 2003 was the first year in which Zargon's reserve estimates were calculated in compliance with the newly implemented National Instrument 51-101 Standards of Disclosure (NI 51-101). These standards establish a higher mandated confidence level for proved and probable reserves and this year's proved and probable assignments are more directly comparable to the prior year's established (proved plus 50 percent probable) reserve estimates. Using this comparison for 2003, Zargon's proved and probable finding, development and acquisition costs, taking into account reserve revisions and changes in estimated future development capital during the period, were $11.49 per barrel of equivalent. If reserve revisions and future development capital were both excluded from the calculation, the 2003 proved and probable finding, development and acquisition costs become $8.92 per barrel of equivalent.

HISTORY OF GROWTH AND RETURNS

Zargon monitors its progress by measuring four key parameters on a per share basis: proved and probable reserves, production, cash flow from operations and net earnings. Using these parameters, Zargon has generated the following growth rates:

- An exceptional 24 percent annual growth rate for these four per share parameters for our entire twelve-year history, and 36 percent per year over the last six years;
- Considering only the fundamental, non-financial and non-price dependent parameters of proved and probable reserves and production, Zargon's growth per share has averaged 15 percent per year over our twelve-year history and 14 percent per year over the last six years.

Other measures of our growth and efficiencies show:

- Forty-one consecutive quarters of positive net earnings as a public company; a record that we believe will be extended into the foreseeable future.
- A historical weighted average return on equity exceeding 18 percent per year.
- Over our history we have raised a total of $42 million in share capital; this investment has delivered more than $70 million in retained earnings, and a record $54 million of cash flow from operations in 2003.

OUTLOOK

Natural gas exploration in Western Canada is at record levels, the price of undeveloped land at Crown sales has again risen sharply and property transactions are defined by very high price parameters. Zargon perceives 2004 as a year to focus largely on organic growth and we have strongly positioned the Company to do so. The land, property and corporate acquisitions made in our earlier years have provided us with a natural gas exploration and oil exploitation platform that is considerably stronger and broader than at any time in our history. Our balance sheet is strong and our operating cash flows are at very high levels. We are budgeting capital expenditures of $45 million in 2004 and we look forward to a capital program that while weighted to natural gas exploration, also has a sizeable component of oil exploitation.

In 2004, natural gas drilling will build on the 2003 exploration successes in our expanding West Central Alberta core area, while Alberta Plains natural gas production volumes will be sustained by a maintenance exploration and development program. Zargon's large inventory of Williston Basin oil exploitation projects will provide steady production gains for this and future years.

Zargon is well positioned for 2004 with a very strong balance sheet and a large project inventory. Recent operational momentum in terms of both production growth and exploration successes, coupled with the current very strong oil and natural gas commodity prices, are providing our Company record cash flows which we continue to redeploy on our natural gas exploration and oil exploitation growth programs. With our industry's current record levels of activity, there is a significant upward cost pressure for property acquisitions, undeveloped land and field services. In these high cost times, we will continue with our disciplined approach, adhering to a focused strategy of exploring and exploiting our existing large asset base, while executing value-added property acquisitions if and when they become available.

ACKNOWLEDGEMENTS

We are grateful for the confidence placed in Zargon by our shareholders and will continue to do our best to reward their trust. Our overriding objective is to enhance the value of their investment while minimizing the risk to its integrity. We acknowledge with pleasure the support and counsel of our Board of Directors and we enjoy and share the commitment of our staff, consultants and advisors to Zargon's growth and prosperity.

Respectfully Submitted,

C.H. Hansen
President and Chief Executive Officer
March 23, 2004

Zargon's oil and natural gas properties are located in three distinct core areas that provide a balance of natural gas/oil production and high-risk/low-risk activities.

A. West Central Alberta

B. Alberta Plains

C. Williston Basin

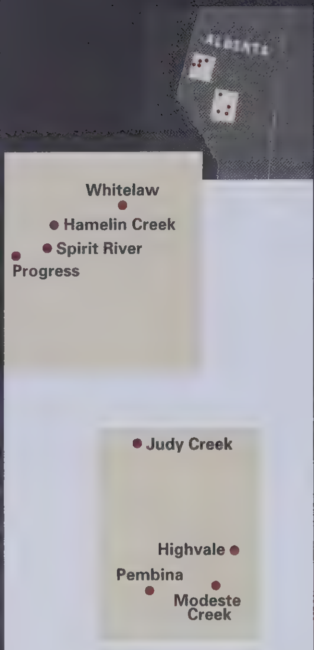
SUMMARY DESCRIPTION

Zargon's principal oil and natural gas properties are located in three distinct core areas, each with its own unique geological and operational features that together provide Zargon a balance of natural gas/oil production and high-risk/low-risk activities. Despite these varying characteristics, Zargon's basic technical skills, including seismic interpretation, detailed geological analysis, reservoir engineering and production engineering enable us to efficiently exploit and explore oil and natural gas resource opportunities in each core area.

- The West Central Alberta core area is comprised of natural gas prone properties located at Highvale, Pembina and the Peace River Arch. In each of these properties Zargon has established a strong land position and is pursuing growth in natural gas reserves and production through a grass roots exploration strategy.
- The Alberta Plains core area consists of oil and gas properties in eastern and southern Alberta. These properties have a relatively established production base associated with an inventory of undeveloped lands and drilling prospects that provide the resource inputs to maintain existing production levels over the medium term.
- The Williston Basin core area is located in southeast Saskatchewan, southwest Manitoba and the northern portion of the state of North Dakota. The area is comprised of long-life producing Mississippian oil properties containing a large volume of oil-in-place. The exploitation of this oil-in-place resource should provide sustainable production and reserve growth for the foreseeable future.

2003 CORE AREA STATISTICAL SUMMARY

	2003 Q4 Equivalent Production (boe/d)	2003 Equivalent Production (boe/d)	2003 Annual Production Growth (percent)	2003 Proved and Probable Reserves (mboe)	2003 Annual Reserve Growth (percent)	2003 Undev. Land (thousand net acres)	2003 Undev. Land Growth (percent)	2003 Capital Program ($ million)
West Central Alberta	1,986	1,472	139	4,287	18	174	59	15.5
Alberta Plains	3,519	3,525	(2)	9,458	(12)	185	(2)	9.3
Williston Basin	2,515	2,449	14	11,249	13	39	20	15.1
Total	8,020	7,446	17	24,994	3	398	20	39.9



West Central Alberta

The West Central Alberta core area provides Zargon substantial natural gas exploration growth opportunities.

In 2003, Zargon continued to aggressively pursue a natural gas exploration strategy in three separate geographic areas in West Central Alberta. Despite having varied geological play types and risk profiles, taken together the three projects form a balanced and successful natural gas exploration program. During the year, Zargon redeployed record Company cash flows to work the West Central Alberta exploration initiative, allocating 39 percent of the total capital program and 42 percent of the total drilling budget to the West Central Alberta core area.

- The Highvale area, located west of Edmonton, has a higher reward, but similar geological and infrastructure characteristics as Zargon's historically successful Jarrow property. A combination of seismically defined structural prospects, stacked medium depth targets, 43 thousand net acres of undeveloped land, and control over local infrastructure provides a platform for Zargon to explore and increase production from this area.

2003 ACTIVITIES

- Acquired 69 thousand net acres of Crown and freehold undeveloped land at an average price of $70 per acre, increasing undeveloped acreage by 59 percent to 174 thousand net acres.
- Shot 110 kilometres of 2D seismic on 10 separate programs.
- Drilled 17.8 net wells, resulting in 14.8 net gas wells, 1.0 net oil well and 2.0 net dry holes.
- Initiated production from a Zargon-constructed and operated natural gas facility at Pembina (Rat Creek). Constructed 10 kilometres of pipelines tieing in four natural gas wells.
- Shot a 7.7 square kilometre 3D survey and drilled a Belloy well at Progress on the Peace River Arch that is currently producing three million cubic feet per day.
- Spent $15.55 million on West Central Alberta capital programs, including $7.50 million on undeveloped land and seismic programs.
- Increased West Central Alberta production by 139 percent to an average of 1,472 barrels of equivalent per day. By fourth quarter 2003 further exploration successes had increased the core area's production to 1,986 barrels of equivalent per day.

2004 PLANS

- Continue to expand and explore the substantial West Central Alberta undeveloped land base, through the shooting of 2D and 3D seismic, building of natural gas exploration projects and the drilling of exploration wells.
- In particular, the 2004 capital budget calls for three net wells in the Highvale area, ten net wells in the Pembina shallow natural gas project, and seven net wells in the Peace River Arch project area.
- Follow up the 2003 Progress and Hamelin Creek exploration discoveries with development drilling programs.
- Grow 2004 natural gas production by 70 percent over 2003 levels.

- In the Pembina area, Zargon is pursuing shallow Edmonton sands at depths up to 900 metres. The project is characterized by multiple sand, low pressure gas targets that can provide initial gas production rates of up to 750 thousand cubic feet per day. Although assembling a land position in the area has been challenging, due to shallow rights held by underlying deeper producing formations, Zargon has acquired an inventory of 48 thousand net acres of undeveloped land in this area that will be systematically developed over the next two years. The Pembina area also includes the Modeste Creek Belly River waterflood project that holds 12 million barrels of working interest exploitable oil-in-place.
- The third major area of the West Central core area is the Peace River Arch where Zargon has been executing a grass roots natural gas exploration strategy that commences with the establishment of a substantial undeveloped land inventory. Following the land acquisition phase, 2D and 3D seismic is acquired that ultimately leads to the drilling of multi-zone natural gas exploration targets. Zargon has established an undeveloped land base of over 70 thousand net acres in this area that will be actively and aggressively explored.

Zargon drilled 17.8 net wells in the West Central area in 2003 and produced an average of 260 barrels per day of oil and 7.27 million cubic feet per day of natural gas. In the fourth quarter, natural gas production had increased to 10.45 million cubic feet per day. During the year, the West Central core area accounted for 29 percent of Zargon's natural gas production volumes and by year end 32 percent of Zargon's proved and probable natural gas reserves. Reflecting the successful execution of Zargon's grass roots exploration effort, the core area's 2003 natural gas production volumes increased 215 percent over the prior year's levels. At year end, Zargon's inventory of undeveloped lands in West Central Alberta has increased to 174 thousand net acres, a 350 percent increase since the beginning of 2002.

WEST CENTRAL ALBERTA

	2003	2002	2001	2000
Average Production				
Oil (bbl/d)	**260**	234	156	159
Natural gas (mmcf/d)	**7.27**	2.31	1.97	1.99
Total Proved Reserves				
Oil (mbbl)	**411**	539	409	399
Natural gas (bcf)	**15.19**	16.28	10.25	9.10
Total Proved and Probable Reserves				
Oil (mbbl)	**585**	618	488	486
Natural gas (bcf)	**22.19**	18.56	11.61	10.41
Undeveloped Lands				
Net acres (thousands)	**173.6**	109.1	38.4	18.1
Drilling Activities				
Net wells	**17.8**	12.8	4.1	9.6
Capital Expenditures ($ million)				
Net property acquisitions	**(2.33)**	5.25	0.48	(0.14)
Undeveloped land, seismic, geological	**7.50**	4.55	1.20	0.53
Drilling, completion, equipping and facilities	**10.38**	7.12	2.47	2.29
Total expenditures	**15.55**	16.92	4.15	2.68

HIGHVALE

Employing a similar model as Jarrow, Zargon's development of the Highvale property was initiated in the spring of 2002 with the acquisition of lands, operated facility ownership and a small base of production as part of the Hadrian corporate acquisition. Following a successful three-well exploration program, new production was tied into expanded facilities by December 2002. In 2003, the property contributed 2.59 million cubic feet per day of natural gas to Zargon's interest.

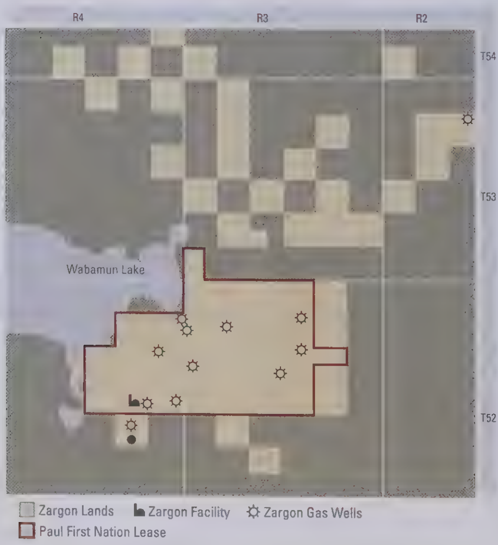
In 2003, further drilling was deferred as Zargon focused on the shooting of seismic and on the negotiation of a new 16 thousand net acre lease with the Paul First Nation. By the end of the year, the inventory of undeveloped lands that complement the existing Zargon-operated wells and facilities had more than tripled. An active year is planned for the Highvale property in 2004. In the first quarter, a 10 square kilometre 3D seismic program was shot and one exploration well was drilled. A minimum of two additional exploration wells are planned for the remainder of the year.

PEMBINA

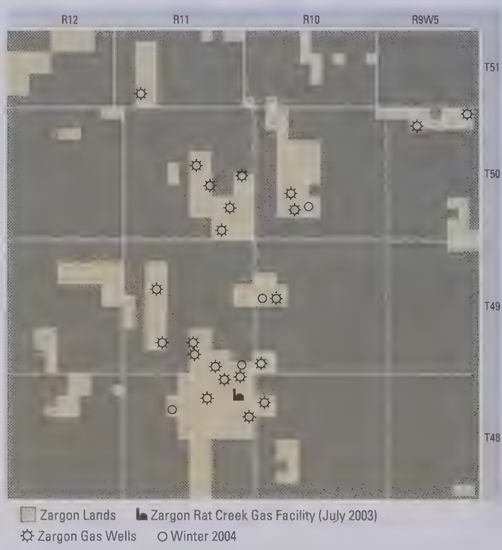
A significant milestone in the Pembina area in 2003 was the initiation of natural gas production volumes at Zargon's Rat Creek compression facility. This facility was commissioned in July 2003 with the tie-in of 3.0 net wells, which averaged 2.81 million cubic feet per day in the fourth quarter to Zargon's interest. In the first half of 2004, three net additional wells will be tied-in to the facility and a similar number of new wells will be drilled in the vicinity of this Zargon-operated gathering system.

In 2004, Zargon plans to replicate the Pembina (Rat Creek) shallow natural gas success in an expanded area. Our 2003 exploration successes in the greater Pembina area offer encouragement that Zargon will be able to develop and tie-in other shallow gas production projects in 2004. However, the access to undeveloped land to pursue these shallow gas concepts continues to be a challenge in the current highly competitive environment. In total, Zargon drilled 9.7 net natural gas wells in the Pembina area in 2003.

HIGHVALE PROPERTY, WEST CENTRAL ALBERTA



PEMBINA PROPERTY, WEST CENTRAL ALBERTA



As an adjunct to the Pembina project, Zargon has agreed to drill a minimum of two wells and possibly five wells on a large land block located on the Blackfeet Indian Reservation in the northern portion of the state of Montana. Although several hundred kilometres apart, we view that the Blackfeet and Pembina properties have many similarities in terms of their shallow depth, low-pressure natural gas shows and completion operations. With the drilling of five wells, Zargon has the opportunity to earn in excess of 29 thousand net undeveloped acres of natural gas prospective land that has the potential to lead to a sizeable natural gas development project in subsequent years.

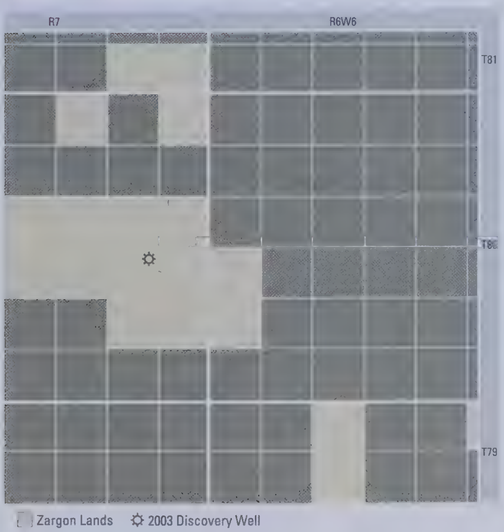
PEACE RIVER ARCH

Over the last two years Zargon has assembled over 72 thousand net acres of undeveloped land in the Peace River Arch, most of this acquired prior to the significant price escalation recently experienced in Alberta Crown land sales. The area is characterized by its potential for stacked medium depth gas-bearing formations, primarily Cretaceous and Triassic targets with deeper opportunities existing in the Kiskatinaw and Mississippian Belloy formations.

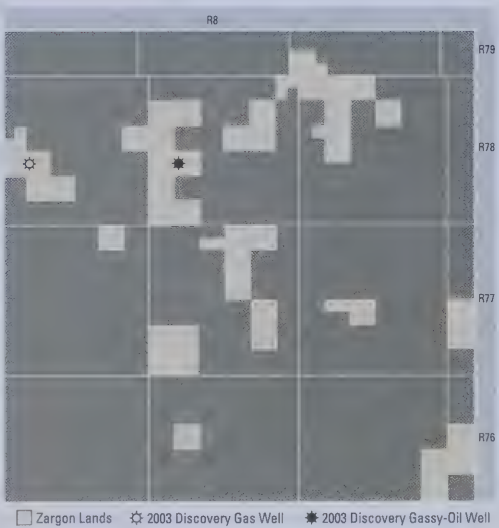
The 2003 year was a watershed year for Zargon in the Peace River Arch as exploration efforts led to the drilling of seven 100 percent wells, resulting in four gas wells, one oil well and two dry holes. Of notable significance was the drilling of a 2,400 metre 100 percent working interest Belloy test at the Progress property. The well was successfully completed and tied-in to area facilities in September 2003 and is currently producing at a restricted rate of three million cubic feet per day.

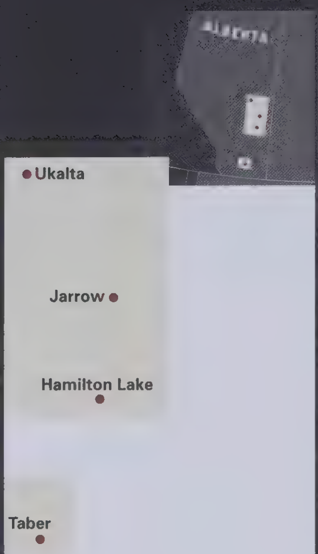
Other significant exploration successes occurred in the fourth quarter of 2003 with two new discoveries on the Hamelin Creek and Progress land blocks. At Hamelin Creek a Dunvegan/Gething gas well is scheduled to be tied-in during the 2004 second quarter at rates exceeding one million cubic feet per day. The current geological mapping suggests that as many as three additional Dunvegan gas wells may be drilled this year on the Hamelin Creek land block. At Progress, a fourth quarter new pool Triassic gassy oil well will also be tied-in to area facilities in the 2004 second quarter. Follow-up drilling on this project is planned later this summer.

HAMELIN CREEK AREA



PROGRESS AREA





Alberta Plains

The Alberta Plains core area provides Zargon stable production volumes that can be sustained with only moderate capital expenditures leaving substantial surplus cash flows to be redeployed in other core ares.

In the Alberta Plains, Zargon developed and executed its first significant natural gas growth business strategy at Jarrow. The cornerstone of the strategy was built around acquiring a dominant land position enhanced by ownership in existing infrastructure, followed by geologically and seismically defined drilling. The properties in the Alberta Plains core area have experienced significant development and production growth in the past and are now positioned to deliver substantial surplus cash flows that can fund other growth opportunities in other areas. Production will be maintained by the optimization of existing wells and by steady seismically defined development and exploration programs on the Company's existing land base.

With a relatively stable production base representing 47 percent of total 2003 production, Zargon spent only 23 percent of its capital expenditures in the Alberta Plains to maintain production level with the prior year. In 2003, certain non-core higher operating cost properties in the Plains area with limited upside were divested, taking advantage of high prices in natural gas properties.

2003 ACTIVITIES

- Shot 185 kilometres of 2D seismic in three separate programs.
- Purchased 16 thousand net acres of land at Crown sales at an average cost of $71 per acre.
- Drilled 12.8 net wells, resulting in 9.8 net gas wells, 1.0 net oil well and 2.0 net dry holes.
- Constructed 15 kilometres of pipelines, that entailed the tie-in of 11 natural gas wells into existing gathering systems and the construction of a Taber solution gas conservation project.
- Spent $9.27 million on Alberta Plains area capital programs, or only 30 percent of the field cash flow generated by the Plains properties.
- Maintained stable production volumes at 3,525 barrels of equivalent per day.

2004 PLANS

- Continue with Zargon's effective program of shooting 2D seismic, drilling wells, reworking existing wells and optimizing facilities to maintain current production volumes. A total of 15 net wells are planned in the Jarrow, Hamilton Lake, Taber and Ukalta properties.
- Shoot a 20 square kilometre 3D seismic program over the Jarrow property to identify new exploration activities and to accelerate the development of the existing pools.
- Maximize the value of the area's large undeveloped land base through farm-outs of higher risk or lower deliverability opportunities.
- Maintain stable production base at approximately 3,500 barrels of equivalent per day.

In 2003, the Alberta Plains core area contributed 69 percent of Zargon's natural gas production volumes and represented 66 percent of Zargon's year-end total proved and probable natural gas reserves. Consistent with the Company's sustainable harvest strategy for its mature properties, the core area's 2003 production volumes were essentially unchanged from 2002 at 3,525 barrels of equivalent per day.

The three most significant properties in the Alberta Plains core area are the Taber oil property in southern Alberta and the Hamilton Lake and Jarrow properties in east central Alberta.

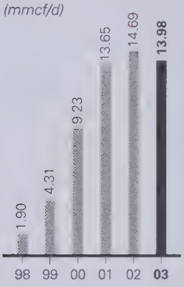
The Taber property is a medium gravity oil property that produced 422 barrels of equivalent per day in 2003 (412 barrels of oil per day and 0.06 million cubic feet of natural gas per day). The property is characterized by a complex series of Mannville channel oil sands at a depth of about 1,000 metres. Collectively, these sands hold more than 10 million barrels of working interest oil-in-place that are being exploited by two separate waterflood projects. In 2004, further waterflood modifications and a minor development program are planned.

The Hamilton Lake property is comprised primarily of Cretaceous natural gas sands at depths up to 1,000 metres that averaged 458 barrels of equivalent per day in 2003 (2.16 million cubic feet of natural gas per day and 98 barrels of oil per day). The property includes 34 thousand net acres of undeveloped land, much of which is prospective for extensive but lower deliverability natural gas sands. In 2004 Zargon plans to drill a few higher deliverability targets, but will also seek to initiate large farm-outs to industry partners to efficiently develop these other resource opportunities.

ALBERTA PLAINS

	2003	2002	2001	2000
Average Production				
Oil (bbl/d)	**640**	660	716	595
Natural gas (mmcf/d)	**17.31**	17.52	16.45	12.41
Total Proved Reserves				
Oil (mbbl)	**1,350**	1,676	1,748	1,876
Natural gas (bcf)	**34.21**	47.41	49.59	49.57
Total Proved and Probable Reserves				
Oil (mbbl)	**1,873**	2,065	2,127	2,259
Natural gas (bcf)	**45.51**	51.72	54.89	56.34
Undeveloped Lands				
Net acres (thousands)	**185.4**	189.3	173.7	169.1
Drilling Activities				
Net wells	**12.8**	14.9	40.5	24.1
Capital Expenditures ($ million)				
Net property acquisitions	**(1.16)**	5.20	(4.90)	5.17
Undeveloped land, seismic, geological	**3.04**	1.48	6.19	4.63
Drilling, completion, equipping and facilities	**7.39**	5.68	16.86	10.11
Total expenditures	**9.27**	12.36	18.15	19.91

JARROW WORKING INTEREST NATURAL GAS PRODUCTION
(mmcf/d)

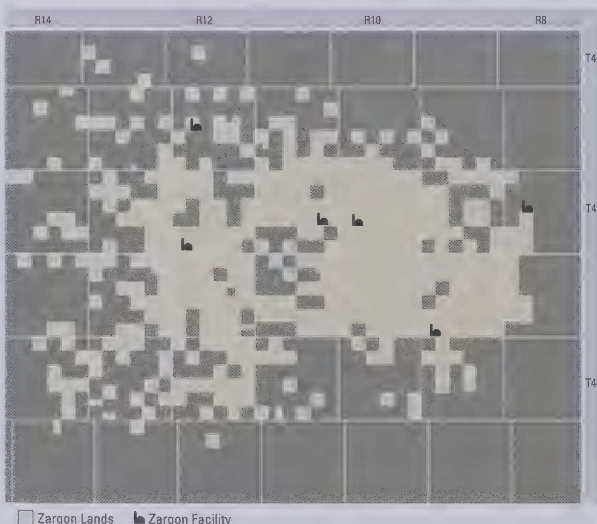


JARROW

Jarrow has been Zargon's largest producing property since 1999, and is characterized by a series of multi-zone Cretaceous gas sands at depths up to 700 metres. The property provided Zargon with substantial production and reserves growth early in its life cycle. Since 2001, it has been maintained at relatively stable production levels through development and exploration drilling programs timed to keep area facilities operating at or near design capacity. For the foreseeable future, the current production rates should be maintained by drilling about 12 net wells per year. The locations for these wells will be derived from the continued evaluation and expansion of the area's comprehensive seismic base on more than 130 thousand net acres of undeveloped land.

In 2003 Zargon drilled 10.5 net wells at Jarrow, which resulted in 8.5 net natural gas wells and 2.0 net dry holes. The Jarrow property produced 2,338 barrels of equivalent in 2003 (13.98 million cubic feet of natural gas per day and eight barrels of oil per day). Reflecting the tie-in of the fall drilling program's wells, Jarrow production increased to 14.35 million cubic feet per day in the fourth quarter of 2003.

JARROW PROPERTY, ALBERTA PLAINS



Williston Basin

Williston Basin

The Williston Basin core area provides Zargon a stable oil production base with substantial long-term exploitation growth potential.

Zargon's Williston Basin core area is the Company's most important oil-producing area. The area encompasses long-life oil properties in southeast Saskatchewan, southwest Manitoba and the northern part of the state of North Dakota. The properties are located in relatively close geographical proximity, and are all producing from Mississippian carbonate reservoirs at depths up to 1,500 metres.

The Williston Basin properties have in general been acquired for their exploitation potential. Containing large volumes of oil-in-place, these properties are suitable candidates for increases in ultimate recoverable reserves through the application of (i) waterflood pressure maintenance technologies, (ii) 3D seismic and (iii) horizontal drilling. Usually, the efficient exploitation of the properties requires the implementation of some form of each of these three technologies. The standard exploitation process starts with a property acquisition phase that is followed by a waterflood initiation or enhancement program. After reservoir pressure support has been regained through water injections and the reservoirs have been characterized with 3D seismic programs, horizontal wells are drilled to accelerate the recovery of the remaining reserves.

Zargon is currently working on 14 Williston Basin exploitation projects that contain 130 million barrels of working interest oil-in-place. As outlined in the following table, these projects are at various stages of development but they have the common characteristic of a substantial remaining exploitation potential and a long-life shallow-decline production profile.

2003 ACTIVITIES

- Acquired the Truro, North Dakota producing oil property with 200 barrels per day of stable production and exploitation potential.
- Shot 50 square kilometres of 3D seismic on five separate programs.
- Initiated new or enhanced waterfloods on three projects.
- Drilled 8.0 net gross wells, resulting in 3.0 net horizontal oil wells, 3.0 net vertical oil wells and 2.0 net dry holes.
- Spent $15.09 million on capital projects, or 88 percent of the field cash flow generated by the Williston Basin properties.
- Increased Williston Basin production by 14 percent to 2,449 barrels of equivalent per day.

2004 PLANS

- Continue the exploitation and development of the large Williston Basin resource base by shooting 3D seismic, implementing or modifying water projects and drilling horizontal or vertical wells.
- Specifically, initiate three additional waterflood projects and drill six net horizontal and four net vertical wells.
- Seek to acquire additional North Dakota oil properties with significant exploitation potential.
- Grow Williston Basin 2004 oil production by 15 percent over 2003 levels.

WILLISTON BASIN EXPLOITATION PROJECTS

	Working Interest Oil-in-place (mmbbl)	Initiate or Re-configure Waterflood	Shoot 3D Seismic	Drill Horizontal Wells
North Dakota				
Haas	47	Implemented 2002	Completed 2003	In progress
Truro	10	Implemented	Scheduled	Planned
Mackobee	6	Planned	Planned	Planned
Subtotal North Dakota	63			
Saskatchewan				
Frys East	5	Implemented 2002	Completed	In progress
Frys West	5	Implemented 2003	Completed	Planned
Elswick	6	Implemented 2003	Completed	In progress
Carnduff	4	In progress	Completed 2003	Scheduled
Halbrite	5	Implemented 2003	Completed 2003	Scheduled
Steelman Unit 8	7	Implemented	Planned	Planned
Steelman West	4	Planned	Planned	Planned
Workman	5	Planned	Planned	Planned
Steelman North	10	Planned	Planned	Planned
Pinto	6	Planned	Completed 2003	Planned
Huntoon	10	Planned	Planned	Planned
Subtotal Saskatchewan	67			

WILLISTON BASIN

HAAS, NORTH DAKOTA

In 2003, the Williston Basin core area contributed 73 percent of the Company's oil production and 82 percent of the year end proved and probable oil reserves. Consistent with the prior year's strategy, Zargon continued to high-grade its properties in 2003 by divesting selected high operating cost properties.

Williston Basin production averaged 2,449 barrels of oil equivalent per day in 2003, a 14 percent gain from the 2002 levels. At the end of 2003, the proved and probable reserve life was a substantial 12.2 years, which reflects the long-life characteristic of these properties.

WILLISTON BASIN

	2003	2002	2001	2000
Average Production				
Oil (bbl/d)	**2,387**	2,074	1,569	971
Natural gas (mmcf/d)	**0.37**	0.46	0.25	0.09
Total Proved Reserves				
Oil (mbbl)	**8,744**	8,899	8,323	4,065
Natural gas (bcf)	**0.72**	0.85	0.89	0.49
Total Proved and Probable Reserves				
Oil (mbbl)	**11,105**	9,761	9,336	4,762
Natural gas (bcf)	**0.86**	0.93	0.99	0.57
Undeveloped Lands				
Net acres (thousands)	**39.4**	32.9	28.6	25.9
Drilling Activities				
Net wells	**8.0**	3.9	3.1	4.9
Capital Expenditures ($ million)				
Net property acquisitions	**6.10**	1.20	28.41	4.32
Undeveloped land, seismic, geological	**2.13**	0.90	1.49	0.83
Drilling, completion, equipping and facilities	**6.86**	4.17	2.98	2.77
Total expenditures	**15.09**	6.27	32.88	7.92

HAAS, NORTH DAKOTA

The Haas, North Dakota property is Zargon's largest Williston Basin property and represents an excellent example of a successful exploitation strategy. The property was acquired in the 2001 Herc Oil corporate acquisition. After a detailed geological and engineering review, Zargon made a September 2002 application to the North Dakota Industrial Commission to expand the existing waterflood by adding 4,000 barrels per day of water injections through the conversion of five existing producers into injectors. The waterflood application project was approved and implemented by year end 2002 and one vertical well was drilled. Oil production consequently increased 44 percent from 516 barrels per day (Q3 2002) to 744 barrels per day (Q2 2003). A 3D seismic survey was shot in summer 2003 and the first horizontal development well in this phase of development was drilled in December 2003. This program will be followed by an injector conversion and a minimum of two additional horizontal wells in 2004.

HIGHLIGHTS

Zargon had an active and successful year in 2003, delivering a 17 percent gain in production, with natural gas production volumes climbing 23 percent, and oil and liquids production volumes increasing 11 percent. On a production per share basis, Zargon produced 418 barrels of equivalent per day per million shares in 2003, a 14 percent gain over the 2002 levels. Also during the year, Zargon's undeveloped land inventory increased 20 percent to 398 thousand net acres and the drilling program was expanded by 22 percent to 38.6 net wells.

	2003	2002	Percent Change
Undeveloped land (thousand net acres)	**398**	331	20
Wells drilled, net	**38.6**	31.6	22
Natural gas production (mmcf/d)	**24.95**	20.29	23
Oil and liquids production (bbl/d)	**3,287**	2,968	11
Year-end proved and probable natural gas reserves (bcf)	**68.58**	71.21	(4)
Year-end proved and probable oil and liquid reserves (mmbbl)	**13.57**	12.45	9

LAND AND SEISMIC

Zargon's undeveloped land inventory increased 20 percent in 2003 to 398 thousand net acres. The year's acquisitions were primarily focused on natural gas opportunities in the West Central Alberta core area, where Zargon's undeveloped land inventory increased by 59 percent to 174 thousand net acres.

During the year, the Company spent $6.98 million on expanding and maintaining the undeveloped land inventory. Despite increasing Crown land prices throughout the year, Zargon was able to acquire, at a reasonable average cost of $81 per acre, a total of 77 thousand net acres of Crown lands for $6.20 million. In 2002, Crown sale purchases of 73 thousand net acres were acquired for $4.20 million or $58 per acre. In 2004, Crown sale prices have continued to escalate and Zargon will reduce its focus on land acquisition while accelerating the efficient exploration of its substantial undeveloped land base.

The independent firm Seaton-Jordan & Associates Ltd. ("Seaton-Jordan") has valued Zargon's undeveloped land holdings as of December 31, 2003 at $28.95 million, up 29 percent from last year's $22.37 million appraisal. This analysis incorporates an average undeveloped acreage price of $73 per acre, compared to the 2002 and 2001 respective estimates of $68 and $77 per acre.

As part of Zargon's continuing exploration focus, the Company shot 295 kilometres of 2D seismic in 2003. Over 60 square kilometres of 3D seismic surveys were also conducted, mostly on oil exploitation projects in the Williston Basin. Total geological and geophysical costs in 2003 were $5.69 million, a 130 percent increase over the prior year's expenditure of $2.47 million. Capital expenditures for undeveloped land and seismic during the year totalled $12.67 million, a highly front-end-weighted 32 percent of the 2003 capital program, as compared to $6.93 million or 19 percent of the 2002 capital program.

UNDEVELOPED LAND

As at December 31 (thousand net acres)	2003	2002	2001
West Central Alberta	**173.6**	109.1	38.4
Alberta Plains	**185.4**	189.3	173.7
Williston Basin	**39.4**	32.9	28.6
Total	**398.4**	331.3	240.7
Average Zargon working interest (%)	**86**	84	82

DRILLING, COMPLETION AND WORKOVERS

Zargon drilled a total of 38.6 net wells in 2003, a 22 percent increase in activity from 2002. The 2003 program resulted in 24.6 net natural gas wells, 8.0 net oil wells, and 6.0 net dry holes.

DRILLING ACTIVITY

	2003		2002		2001	
Number of Wells	Gross	Net	Gross	Net	Gross	Net
Oil	**11**	**8.0**	7	6.9	14	11.1
Natural Gas	**35**	**24.6**	24	20.7	30	22.7
Dry	**6**	**6.0**	4	4.0	14	13.9
Total	**52**	**38.6**	35	31.6	58	47.7
Exploratory	**35**	**29.4**	26	23.0	41	37.2
Development	**17**	**9.2**	9	8.6	17	10.5
Total	**52**	**38.6**	35	31.6	58	47.7
West Central Alberta	**23**	**17.8**	14	12.8	5	4.1
Alberta Plains	**20**	**12.8**	17	14.9	47	40.5
Williston Basin	**9**	**8.0**	4	3.9	6	3.1
Total	**52**	**38.6**	35	31.6	58	47.7
Average net Zargon working interest (%)	**74**		90		82	

Zargon's success ratio was 84 percent for its 2003 drilling program, consistent with the prior year's 87 percent success ratio. This success ratio was achieved through disciplined capital allocation while still maintaining a 76 percent weighting to exploration wells, up slightly from a 73 percent exploratory weighting in 2002.

During the year, Zargon operated 40 gross wells with an average working interest of 92 percent. Including Zargon's minor participations in an additional 12 non-operated wells brought Zargon's average interest in the year's drilling program down to 74 percent. More than 70 percent of the year's drilling activities related to Alberta natural gas targets, with the majority of the natural gas program allocated to West Central Alberta exploration. With very strong commodity prices supporting expanded natural gas and oil development drilling programs, 45 net wells are planned in 2004, emphasizing natural gas exploration in West Central Alberta and Alberta Plains and oil exploitation in the Williston Basin.

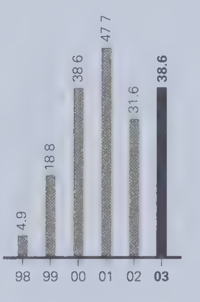
In 2003, expenditures for drilling, completion and workovers totalled $17.30 million, a 39 percent increase from $12.49 million spent in 2002, but similar to the $17.44 million spent in 2001. Expenditures were 13 percent higher on a per well basis due to an increase in average drilling depths as Zargon began to drill some of its deeper West Central Alberta gas exploration targets. Drilling-related expenditures represented a 43 percent share of the year's total capital program, as compared to the 35 percent recorded in the prior year.

UNDEVELOPED LAND

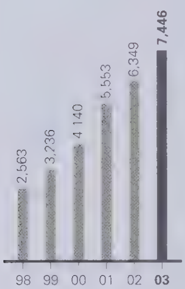
(thousand net acres)

DRILLING ACTIVITY

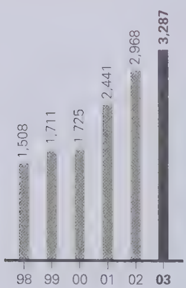
(net wells)



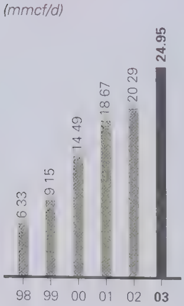
PRODUCTION
(boe/d)



OIL AND LIQUID PRODUCTION
(bbl/d)



NATURAL GAS PRODUCTION
(mmcf/d)



PRODUCTION EQUIPMENT AND FACILITIES

Zargon spent $7.33 million on gas plant expansion and construction, oil battery modifications and construction and the installation of approximately 21 kilometres of pipelines in 2003. This is a 64 percent increase over the prior year's expenditures of $4.48 million and represents 18 percent of the 2003 total capital program, up substantially from the prior year's 13 percent allocation. During the year, larger facility projects included a new compression facility and tie-ins at the West Central Alberta Pembina property, waterflood implementations at the Williston Basin oil exploitation properties of Frys, Halbrite and Weyburn, and ongoing tie-ins relating to the exploration and development drilling at the Alberta Plains Jarrow natural gas property.

PROPERTY ACQUISITIONS

Zargon's net corporate and property acquisitions totalled $2.61 million, representing only seven percent of the Company's total capital expenditures in 2003, down sharply from the 33 and 43 percent acquisition weightings in 2002 and 2001, respectively. Following the 2002 Hadrian Energy Corp. acquisition and the 2001 Herc Oil Corp. acquisition, there were no corporate acquisitions in 2003.

During 2003, Zargon completed five property acquisitions for a total of $7.83 million. The largest of these was a $4.95 million purchase of the exploitable Truro Unit oil property in Renville County, North Dakota. The remaining purchases generally related to the expansion of existing interests pertaining to Williston Basin oil exploitation projects.

To capture the benefits of a strong property market, while upgrading its base Zargon sold six minor properties, mostly in the first half of 2003, for $5.22 million. The sale properties, which had mostly been acquired in various corporate acquisitions, were either small with only minor growth potential or had high operating costs. Combined with the second half 2002 property sales, Zargon sold $8.35 million of generally high cost properties in the last 18 months. With the sale of these properties the Company was able to reduce the 2003 per unit operating costs by six percent during a period of significant industry-wide upward cost pressures. Although Zargon, as a matter of policy, will pursue value-adding property dispositions that upgrade the focus and quality of our properties, significant property sales are not anticipated in 2004.

PRODUCTION

Natural gas sales volumes increased 23 percent in 2003 to average 24.95 million cubic feet per day compared to 20.29 million cubic feet per day in 2002 (2001—18.67 mmcf/d). Increases in natural gas production came mainly from each of the three West Central Alberta major properties of Highvale, Pembina and the Peace River Arch. Crude oil and natural gas liquid sales volumes increased 11 percent in 2003 to 3,287 barrels per day compared to 2,968 barrels per day in 2002 (2001—2,441 bbl/d). These production gains resulted from the Williston Basin oil exploitation drilling program and the Truro acquisition.

Zargon's 2003 average daily production climbed 17 percent, to 7,446 barrels of equivalent per day compared to 6,349 barrels of equivalent per day in 2002 (2001—5,553 boe/d). On a production per share basis, Zargon produced 418 barrels of equivalent per day per million shares in 2003, a 14 percent gain over the 2002 levels. During the year natural gas production represented 56 percent of total volumes, up from a 53 percent weighting in 2002.

RESERVES

Formal disclosure of oil and natural gas reserves as required by National Instrument 51-101 Standards of Disclosure ("NI 51-101") will be included in the Company's annual information form for the year ended December 31, 2003 that will be filed on SEDAR.

Since 1993, the independent engineering firm of McDaniel & Associates Consultants Ltd. ("McDaniel") has evaluated 100 percent of Zargon's reserves. Commencing with the 2003 year-end report Zargon's reserve estimates have been calculated in compliance with the newly implemented NI 51-101. These new NI 51-101 standards establish a higher mandated confidence level for proved and probable reserves. Under NI 51-101, proved reserve estimates are defined as having a 90 percent probability that actual reserves recovered over time will equal or exceed proved reserve estimates. Probable reserves are defined under NI 51-101 so that there are equal (50 percent) probabilities that the actual reserves to be recovered will be less than, or greater than, the proved and probable reserves estimate.

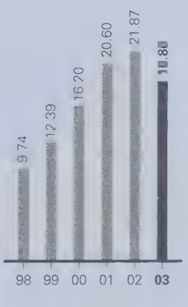
Using the newly implemented NI 51-101 definitions, McDaniel has prepared a report dated March 22, 2004 that assigns the following reserve estimates based on forecast prices and costs as of December 31, 2003:

COMPANY RESERVES [1]

At December 31, 2003	Oil and Liquids (mmbbl)	Natural Gas (bcf)	Equivalents [2] (mmboe)
Proved producing	10.40	38.92	16.89
Proved non-producing	0.11	10.61	1.87
Proved undeveloped	-	0.60	0.10
Total proved	**10.51**	**50.13**	**18.86**
Probable additional	3.06	18.45	6.13
Total proved and probable	**13.57**	**68.58**	**24.99**
Proved reserve life index, years	8.7	4.7	6.3
Proved and probable reserve life index, years	11.0	6.2	8.1

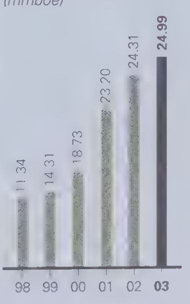
1 Company working interest and gross override receivable reserves before royalties, boe (6:1).
2 Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

PROVED RESERVES
(mmboe)



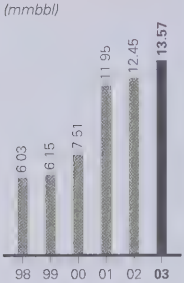
In the McDaniel report, prepared under the new NI 51-101 standards, the proved producing reserve allocation increased from 83 percent to 90 percent of Zargon's total proved reserves. The remaining proved non-producing reserves are comprised primarily of natural gas reserves from recently drilled wells at the West Central Alberta Pembina and the Peace River Arch properties and behind pipe natural gas reserves at the Alberta Plains Jarrow property. Proved undeveloped reserves represent less than one percent of the total proved reserves. McDaniel forecasts $4.86 million of net future (forecast prices) capital costs to deliver the total proved reserve estimate. Zargon's probable reserves generally reflect incremental waterflood recoveries on producing oil properties and improved gas recoveries for currently producing natural gas wells. McDaniel forecasts $6.76 million of net future (forecast prices) capital costs to deliver the total proved and probable reserve estimate.

PROVED AND PROBABLE RESERVES
(mmboe)

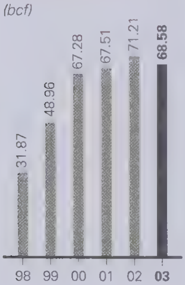


Based on 2003 year end reserves and the McDaniel predicted total proved 2004 production rates of 29.28 million cubic feet of natural gas per day and 3,316 barrels of oil per day, Zargon's proved reserve life index is 8.7 years and 4.7 years for oil and natural gas, respectively. The corresponding proved and probable oil and natural gas reserve life indices are 11.0 and 6.2 years, based on the McDaniel predicted proved and probable 2004 production rates of 30.47 million cubic feet per day of natural gas and 3,395 barrels of oil per day. The relatively high oil reserve life reflects Zargon's portfolio of long-life shallow-decline Williston Basin waterflood projects.

PROVED AND PROBABLE OIL AND LIQUID RESERVES
(mmbbl)



PROVED AND PROBABLE NATURAL GAS RESERVES
(bcf)



RESERVE RECONCILIATION

A reconciliation of these 2003 year-end reserve assignments with the reserves reported in the 2002 year-end report is presented below. In these tables the reserve assignments are not directly comparable to the prior year estimates due to the application of different risk assessments under the new reporting requirements. However, for the proved and probable case, the 2003 year-end assignments are reasonably comparable to proved plus one-half probable, or established, reserves from the prior year. The following tables have been compiled on this basis:

RESERVE RECONCILIATION

	Oil and Liquids (mmbbl)			Natural Gas (bcf)			Equivalents (mmboe)		
	Proved	Probable	Proved & Prob.	Proved	Probable	Proved & Prob.	Proved	Probable	Proved & Prob.
December 31, 2002	11.11	1.34*	12.45*	64.54	6.67*	71.21*	21.87	2.44*	24.31*
Discoveries & extensions	0.52	0.40	0.92	11.82	4.94	16.76	2.49	1.22	3.71
Revisions	(0.66)	0.93	0.27	(15.05)	6.94	(8.11)	(3.17)	2.09	(1.08)
Acquisitions & dispositions	0.74	0.39	1.13	(2.07)	(0.10)	(2.17)	0.39	0.38	0.77
Production	(1.20)	-	(1.20)	(9.11)	-	(9.11)	(2.72)	-	(2.72)
December 31, 2003	10.51	3.06	13.57	50.13	18.45	68.58	18.86	6.13	24.99

* *In this table the December 31, 2002 established (proved plus 50 percent probable) reserves are used as a comparison to December 31, 2003 proved and probable reserves, so as to reflect the equivalent level of risk assigned under the NI 51-101 guidelines.*

Proved reserves at December 31, 2003 declined 14 percent from the prior year. Effectively, the use of the NI 51-101 standards resulted in the reclassification of a component of Zargon's proved reserves into probable reserves. Overall, negative proved reserve revisions totalled 3.17 million barrels of equivalent, or approximately 14 percent of the opening balance. Offsetting 66 percent of these negative proved revisions were positive probable revisions totalling 2.09 million barrels of equivalent. On a proved-only basis, reserve additions from the year's capital programs did not offset the negative reserve revisions.

Eighty percent of the total proved negative reserve revisions were natural gas related. Of these natural gas revisions, approximately half came from the prior year proved non-producing or proved undeveloped natural gas reserve assignments. As a result of the new reporting standards, proved producing natural gas reserves now comprise 78 percent of Zargon's total proved natural gas reserves, as compared to last year's 67 percent allocation. The remainder of the proved natural gas revisions were related to reservoir performance and were concentrated in the Alberta Plains Jarrow property.

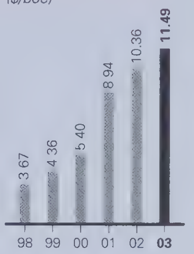
On a proved and probable basis, Zargon increased its reserves by three percent in 2003, with the addition of 3.40 million barrels of equivalent (after revisions) or 4.48 million barrels of equivalent (before revisions), thereby replacing annual production by a factor of 125 percent (164 percent before revisions). These 2003 reserve additions were derived from a $39.91 million net capital expenditure program, which was restrained by the perceived high cost of property acquisitions to 73 percent of corporate cash flow. The year's capital program was also characterized by a large component (32 percent) of front-end undeveloped land and seismic costs that should provide future reserve growth in subsequent years.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

For 2003, Zargon's proved and probable finding, development and acquisition ("FD&A") costs, taking into account reserve revisions and changes in estimated future development capital during the period, were $11.49 per barrel of equivalent. For the purposes of this calculation, the $39.91 million of 2003 net capital additions were combined with a decrease in estimated future development capital for proved and probable reserves of $0.91 million ($6.76 million at December 31, 2003 compared to $7.67 million at December 31, 2002).

PROVED AND PROBABLE FINDING, DEVELOPMENT AND ACQUISITION COSTS

($/boe)



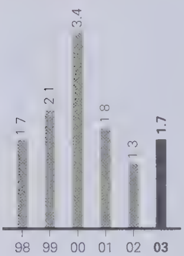
PROVED AND PROBABLE FINDING, DEVELOPMENT AND ACQUISITION COSTS

	2003	2002	2001	2000	1999	1998
Total net capital expenditures ($ million)	**39.91**	35.55	55.18	30.51	16.95	12.48
Total net capital expenditures plus change in forecast future development costs ($ million)	**39.00**	35.57	58.06	32.05	18.09	12.20
Proved and probable reserves (mmboe)						
Open	**24.31**	23.20	18.73	14.31	11.34	8.95
Additions (discoveries, extensions, net acquisitions)	**4.48**	4.68	6.95	5.27	3.52	2.78
Revisions	**(1.08)**	(1.25)	(0.45)	0.66	0.63	0.55
Production	**(2.72)**	(2.32)	(2.03)	(1.51)	(1.18)	(0.94)
Close	**24.99**	24.31	23.20	18.73	14.31	11.34
Proved and probable FD&A costs ($/boe)	**11.49**	10.36	8.94	5.40	4.36	3.67
Proved and probable three year FD&A costs ($/boe)	**9.95**	7.92	6.52	4.65	na	na
Proved and probable FD&A costs excluding prior year revisions ($/boe)	**8.71**	7.60	8.35	6.08	5.14	4.39

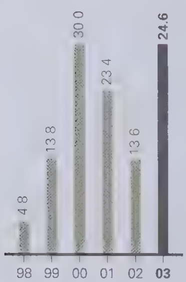
In this table, the established reserves (proved plus 50 percent probable) for the prior years (1998–2002) are used as a comparison to the December 31, 2003 proved and probable reserves, so as to reflect the equivalent level of risk assigned under the NI 51-101 guidelines.

Zargon experienced higher FD&A costs in 2003 due to a combination of factors. Negative natural gas reserve revisions, a capital program emphasizing front-end undeveloped land and seismic costs, and the industry-wide trend to higher costs were key contributors to the 2003 higher costs. Despite this trend to higher costs, the offsetting effect of higher commodity prices has maintained Zargon's return on equity and corporate recycle ratios at very strong levels. Throughout its twelve-year history, Zargon has delivered an average rate of return on book equity in excess of 18 percent per year, and an average proved and probable corporate recycle ratio in excess of 2.2 times.

PROVED AND PROBABLE CORPORATE RECYCLE RATIO



RETURN ON EQUITY
(%)



CORPORATE PERFORMANCE

	2003	2002	2001	2000	1999	1998	Three Year Average (2001–2003)	Six Year Average (1998–2003)	Twelve Year Average (1992–2003)
Corporate cash flow ($/boe) [1]	**20.00**	13.86	16.12	18.15	9.01	6.22	16.87	15.26	13.62
Proved and probable FD&A costs ($/boe) [2]	**11.49**	10.36	8.94	5.40	4.36	3.67	9.95	7.29	6.17
Corporate recycle ratio [3]	**1.7**	1.3	1.8	3.4	2.1	1.7	1.7	2.1	2.2
Return on equity (%) [4]	**24.6**	13.6	23.4	30.0	13.8	4.8	20.7	19.8	18.4

Notes:

1 Corporate cash flow from operations including allowances for current taxes, interest charges and general and administrative costs on a barrel of oil equivalent production basis (6:1).

2 Finding, development and acquisition costs taking into account reserve revisions and changes in estimated future development capital during the period on a barrel of oil equivalent basis (6:1).

3 Corporate recycle ratio is defined as the corporate cash flow per barrel of equivalent divided by proved and probable FD&A costs per barrel of equivalent.

4 Return on equity is defined as the net after tax annual earnings divided by the year average shareholders' equity. Multi-year averages are dollar-weighted.

NET ASSET VALUE

Zargon's oil, natural gas liquids and natural gas reserves were evaluated using McDaniel product price forecasts effective January 1, 2004 prior to provisions for income taxes, interest, debt service charges and general and administrative expenses. It should not be assumed that the following discounted future net property cash flows estimated by McDaniel represent the fair market of the reserves:

BEFORE TAX PRESENT VALUE OF FUTURE NET REVENUE (FORECAST PRICE CASE)

($ million)	Discount Factor 0%	5%	10%	15%
Proved producing	202.4	176.2	155.6	139.7
Proved non-producing	25.7	22.0	19.1	16.8
Proved undeveloped	1.3	0.9	0.7	0.6
Total proved	**229.4**	**199.1**	**175.4**	**157.1**
Probable	86.7	60.1	44.2	34.1
Total proved and probable	**316.1**	**259.2**	**219.6**	**191.2**

BEFORE TAX PRESENT VALUE OF FUTURE NET REVENUE (CONSTANT PRICE CASE)

($ million)	Discount Factor 0%	5%	10%	15%
Proved producing	289.8	237.6	202.8	177.9
Proved non-producing	34.9	29.4	25.2	22.0
Proved undeveloped	1.8	1.4	1.0	0.8
Total proved	**326.5**	**268.4**	**229.0**	**200.7**
Probable	118.3	79.0	57.3	43.9
Total proved and probable	**444.8**	**347.4**	**286.3**	**244.6**

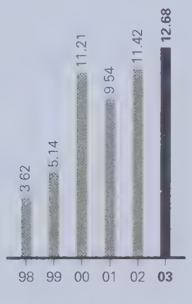
The above discounted future net property cash flows are based on the McDaniel price assumptions that are contained in the following table:

McDANIEL REPORT PRICING ASSUMPTIONS (FORECAST AND CONSTANT PRICE CASES)

	WTI Crude Oil ($US/bbl)	Edm. Par Price ($Cdn/bbl)	Cromer Med. ($Cdn/bbl)	AECO Gas Price ($Cdn/mmbtu)	Exchange Rate ($US/$Cdn)	Inflation Rate (%)
Forecast prices						
2004	29.00	37.70	32.20	5.50	0.75	2.0
2005	26.50	34.30	29.71	5.19	0.75	2.0
2006	25.50	33.00	28.84	4.87	0.75	2.0
2007	25.00	32.30	28.06	4.68	0.75	2.0
2008	25.00	32.30	27.97	4.53	0.75	2.0
Thereafter:	Escalate at 2%/year	Escalate at 2%/year	Escalate at 2%/year	Escalate at 2%/year	0.75	2.0
Constant prices						
2003 Year end	32.78	39.76	34.25	5.87	0.76	–

The following net asset value table shows what is customarily referred to as a "produce-out" net asset value calculation under which the current value of Zargon's reserves would be produced at McDaniel forecast future prices and costs. The value is a snapshot in time as of December 31, 2003 and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. In this analysis, the present value of the proved and probable reserves is calculated at a before tax 10 percent discount rate, and the value assigned to the undeveloped land was provided by the independent firm of Seaton-Jordan and Associates Ltd.

NET ASSET VALUE
(PVBT 10%)
($/diluted share)



NET ASSET VALUE

As at December 31 ($ million)	**2003**	2002	2001	2000	1999	1998
Proved and probable reserves (PVBT 10%) (1) (2)	**219.6**	215.4	175.5	175.0	82.3	54.8
Undeveloped land (3)	**29.0**	22.4	18.5	14.9	9.8	6.3
Working capital	**(6.1)**	(3.5)	(3.5)	(2.5)	(0.1)	(0.2)
Bank debt	**(7.0)**	(25.3)	(24.1)	(15.9)	(14.1)	(6.2)
Proceeds from the exercise of all stock options	**9.1**	6.2	4.0	3.5	3.6	2.5
Net asset value (including stock option dilution)	**244.6**	215.2	170.4	175.0	81.5	57.2
Net asset value per common share						
Basic ($/share)	**13.09**	11.85	9.98	11.98	5.40	3.70
With full dilution ($/share) (4)	**12.68**	11.42	9.54	11.21	5.14	3.62

1 McDaniel estimate of future before tax cash flow discounted at PV 10 percent. Prior years' reserves are presented as established (proved plus 50 percent probable) reserves as the best comparison to December 31, 2003 proved and probable reserves, so as to reflect the equivalent level of risk assigned to these reserves as under the NI 51-101 guidelines.
2 PVBT represents present value before taxes.
3 Seaton-Jordan year-end estimates.
4 Full dilution of shares represent the year-end shares outstanding plus the presumed exercise of all stock options.

If the net asset value calculation is adjusted to assume that the commodity prices received at year end 2003 (Edmonton light crude oil at $39.76 Cdn per barrel and Alberta average natural gas at $5.87 Cdn per mmbtu) will remain constant throughout the future (McDaniel constant price case), the equivalent analysis calculates a 10 percent present value before tax (PVBT) net asset value of $16.14 per fully diluted share.

CORPORATE PERFORMANCE

Throughout its history, Zargon has targeted a benchmark of a greater than 15 percent compounded annual growth rate in per share proved and probable reserves, production, cash flow and earnings. Over its twelve-year history, Zargon has delivered an average composite growth rate of 24 percent per share for these four parameters. In the last six years, the growth rate for the four per share parameters has averaged 36 percent per year. For the two per share non-commodity price sensitive parameters of proved and probable reserves and production, the six and twelve-year compounded annual growth rates have averaged 14 and 15 percent, respectively.

CORPORATE GROWTH PERFORMANCE

	2003	2002	2001	2000	1999	1998	1992	Last Year's Growth (2002–2003)	Six Year Annual Growth (1998–2003)	Twelve Year Annual Growth (1992–2003)
Proved and probable reserves (mmboe) (4) (7)	**24.99**	24.31	23.20	18.73	14.31	11.34	1.25	3	17	31
Boe per share (1) (4) (7)	**1.39**	1.38	1.39	1.31	0.99	0.77	0.31	1	13	15
Production (boe/d) (4)	**7,446**	6,349	5,553	4,140	3,236	2,563	362	17	24	32
Boe/d per million shares (2)(4)	**418**	368	357	287	224	196	89	14	16	15
Cash flow ($ million)	**54.35**	32.12	32.67	27.50	10.64	5.82	0.55	69	56	52
$/share (3)	**2.96**	1.81	2.03	1.86	0.70	0.43	0.16	64	47	30
Net earnings ($ million)	**24.53**	10.68	13.14	11.26	4.26	1.25	0.14	130	81	60
$/share (3)	**1.33**	0.60	0.82	0.76	0.29	0.10	0.05	122	68	35
Average shares outstanding (million)	**17.82**	17.23	15.56	14.41	14.69	13.03	4.05	3	6	14
Year-end shares outstanding (million)	**17.99**	17.64	16.67	14.32	14.42	14.81	4.05	2	4	15
Year-end share price ($)	**13.50**	9.00	7.20	4.45	3.00	2.40	na	50	41	25(5)
Four parameter average annual growth (%) (6)(7)	**55**	0	23	95	94	(11)	-	55	44	44
Four parameter average annual growth per share (%) (6) (7)	**50**	(9)	12	97	74	(19)	-	50	36	24

Notes:

1 Reserves per share are calculated using year-end reserve appraisals and year-end shares outstanding.

2 Production per share is calculated using year average production and weighted average shares outstanding for the year.

3 Cash flow and net earnings per share are presented on a weighted average diluted basis.

4 Assumes six thousand cubic feet of natural gas is equivalent to one barrel of oil.

5 Share price growth rate since the October 1993 initial public offering at $1.50 per share.

6 Four parameters include proved and probable reserves, production, cash flow and net earnings.

7 The prior years' (1992–2002) established (proved plus 50 percent probable) reserves have been used as a comparison to December 31, 2003 proved and probable reserves, so as to reflect the equivalent level of risk assigned to these reserves under the NI 51-101 guidelines.

Management's discussion and analysis ("MD&A") is a review of Zargon Oil & Gas Ltd.'s ("Zargon" or the "Company") 2003 financial results and should be read in conjunction with the audited consolidated financial statements and related notes for the years ended December 31, 2003 and 2002. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). In the MD&A, reserves and production are commonly stated in barrels of equivalent (boe) on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil.

Non-GAAP Measurements: The MD&A contains the term "cash flow from operations"("cash flow"), which should not be considered an alternative to, or more meaningful than, "cash flow from operating activities" as determined in accordance with Canadian GAAP as an indicator of the Company's financial performance. Zargon's determination of cash flow from operations may not be comparable to that reported by other companies. The reconciliation between net earnings and cash flow from operations can be found in the consolidated statements of cash flows in the consolidated financial statements. The Company evaluates its performance based on net earnings and cash flow from operations. The Company considers cash flow from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to repay debt and to fund future growth through capital investment. Cash flow from operations per share is calculated using the diluted weighted average number of shares for the period.

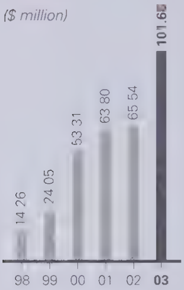
HIGHLIGHTS

The combination of high oil and natural gas prices and strong production volume gains enabled Zargon to achieve record revenues, cash flow from operations and net earnings in 2003, showing gains of 55 percent, 69 percent and 130 percent, respectively, over the prior year. Approximately 80 percent of these annual revenue and cash flow gains came from our natural gas operations, as Zargon's 2003 natural gas production volumes grew 23 percent and natural gas prices increased 66 percent over 2002 levels. Net earnings benefited similarly from these natural gas gains, but in addition were enhanced significantly by the mid-year announcement of future federal tax rate reductions that produced a large one-time reduction in future tax provisions.

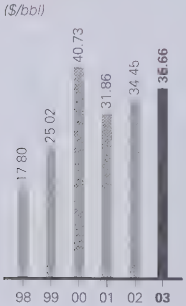
Net capital expenditures for 2003 totalled $39.91 million with $37.30 million allocated to field-related activities, showing a 12 percent increase in overall net expenditures, but a 56 percent increase in field-related expenditures. The significant expansion in 2003 fieldwork came from an active second half 2003 exploration program. The purchase of the Truro Unit in North Dakota was the largest acquisition made in 2003. Over the year, Zargon increased its undeveloped land base by 20 percent at a cost of $6.98 million; shot or acquired seismic at a cost of $5.69 million; drilled, equipped and tied-in wells for $24.63 million and made property acquisitions of $7.83 million. All of these activities were funded by the high cash flows received throughout the year plus non-core property dispositions of $5.22 million. The combined operation and disposition cash flows along with minor stock-option-related equity issuances exceeded the year's capital expenditures, and debt net of working capital was reduced by $15.65 million to $13.09 million at December 31, 2003.

($ million, except per share amounts)	2003	2002	2001
Petroleum and natural gas revenue	**101.66**	65.54	63.80
Cash flow from operations	**54.35**	32.12	32.67
Per diluted share ($)	**2.96**	1.81	2.03
Net earnings	**24.53**	10.68	13.14
Per diluted share ($)	**1.33**	0.60	0.82
Net capital expenditures	**39.91**	35.55	55.18

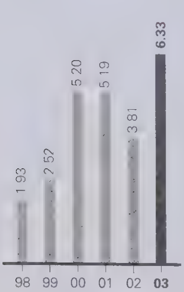
PETROLEUM AND NATURAL GAS REVENUE
($ million)



OIL AND LIQUID PRICES
($/bbl)



NATURAL GAS PRICES
($/mcf)



DETAILED FINANCIAL ANALYSIS

PETROLEUM AND NATURAL GAS REVENUE

Zargon derives its revenue from the production and sale of petroleum (crude oil and natural gas liquids) and natural gas. Petroleum and natural gas revenue exclusive of hedges increased 55 percent to $101.66 million in 2003 from $65.54 million in 2002 due to increased production and higher prices. Production volumes in 2003 increased 17 percent from the prior year, made up of a natural gas production increase of 23 percent and an oil and liquids production increase of 11 percent. The average price of oil and liquids received by Zargon rose to $36.66 per barrel in 2003, up six percent from 2002; however, the major impact came from a 66 percent gain in the average field price of natural gas to $6.33 per thousand cubic feet in 2003.

Because of the large gains in both natural gas production volumes and prices received, the allocation of production revenue in 2003 increased to 57 percent from the sale of natural gas and 43 percent from the sale of oil and liquids, a reversal from the 43 percent from natural gas and 57 percent from oil and liquids in the preceding year.

PETROLEUM (OIL AND NATURAL GAS LIQUIDS) PRICING

Zargon's field oil and liquid prices are adjusted for transportation charges and oil quality differentials from an Edmonton light sweet crude price that varies with world commodity prices. In 2003, Zargon's average oil and liquids field price, exclusive of hedges, rose six percent to $36.66 per barrel from $34.45 per barrel in 2002 and $31.86 per barrel in 2001. The field price differential for Zargon's average blended 30 degree API crude stream was $6.48 per barrel less than the 2003 Edmonton reference crude price, which compares to the 2002 differential of $5.49 per barrel and the 2001 differential of $7.32 per barrel. As the quality and weight of Zargon's crude stream have remained relatively consistent for several years, the movements in the Zargon's price differential is derived from the North American refinery supply and demand factors for sour medium crudes.

NATURAL GAS PRICING

After peaking in March 2003 at $8.90 per thousand cubic feet, Zargon's field natural gas price exclusive of hedges stayed at historically strong levels between $5.00 and $6.70 per thousand cubic feet for the balance of the year. The average natural gas price for 2003 of $6.33 per thousand cubic feet was 66 percent above 2002, 22 percent above both 2001 and 2000, and far above all previous years. The apparent trend to higher Alberta natural gas prices is based on North American supply and demand fundamentals modified by shorter term climatic and storage inventory factors.

Approximately 35 percent of Zargon's 2003 natural gas production was sold under aggregator contracts pursuant to long-term contracts with Cargill Gas Marketing Ltd. (Jarrow—29 percent) and ProGas Limited (Hamilton Lake—six percent), compared to 41 percent in the prior year. The remainder of Zargon's natural gas production was sold by spot sale contracts and Alberta index prices were received. In 2003, Zargon continued with an ongoing trend to develop new West Central Alberta natural gas production, which receives spot sale natural gas prices and is not subject to aggregator contract prices.

HEDGING ACTIVITIES

Zargon's commodity price risk management policy uses forward sales, options, puts and costless collars for, on average, 20 to 30 percent of our net petroleum and natural gas production in order to partially offset the effects of large price fluctuations. As both Canadian oil and natural gas field prices are closely correlated to US dollar denominated markets, Zargon will also place US/Cdn currency exchange hedges when considered prudent.

Because our hedging strategy is protective in nature and is designed to guard the Company against extreme effects from sudden falls in prices and revenues, upward price spikes and trends tend to produce overall losses. Oil and natural gas prices moved to very high levels in first quarter 2003 and then trended to lower, although still historically high levels, as the year progressed. As a consequence, hedging activities produced a loss of $2.22 million in the first quarter and smaller losses of $0.47 million and $0.35 million in the second and third quarters respectively. The currency exchange collar in place throughout 2003 was positive all year and provided an overall gain of $1.22 million, partially offsetting the commodity hedge losses. Lower natural gas prices in the fourth quarter, plus increased strength in the Canadian dollar, produced a quarterly hedge gain of $0.17 million. For the full year 2003, the hedge loss was $2.88 million, which compares to a gain of $0.67 million in 2002 and hedge losses of $0.57 million in 2001 and $2.73 million in 2000. A similar level of risk management was employed in all four years.

During the year, oil and currency hedges resulted in a $1.04 million reduction of 2003 oil and liquid revenues, which is equivalent to a $0.87 per barrel charge against the year's total oil and liquid production. Natural gas hedges reduced Zargon's 2003 gas revenues by $1.84 million, equivalent to a $0.20 per thousand cubic feet charge on the year's total natural gas production.

ROYALTIES

Royalties include payments made to the Crown, freehold owners and third parties. Reported royalties also include credits received through the Alberta Royalty Tax Credit (ARTC) program, the cost of the Saskatchewan Resource Surcharge (SRC) and the cost of the North Dakota state taxes. During 2003, total royalties were $22.51 million, an increase of 67 percent from $13.51 million in 2002. Royalties as a percentage of gross revenue (before hedging adjustments) were 22.1 percent in 2003 compared to 20.6 percent in 2002 and 22.3 percent in 2001. On a commodity basis, oil royalties averaged 20.2 percent (before hedging) in 2003, a small increase from the previous year's average of 19.9 percent. Natural gas royalties averaged 23.5 percent, up from 21.5 percent in the prior year, as a result of the addition of several higher production natural gas wells in 2003 that carry a higher effective royalty rate.

During 2003, 56 percent of the total royalties were paid to provincial and state governments with the remainder paid to freehold owners and other third parties. Royalties payable to the Province of Alberta on qualifying properties are reduced through the ARTC program. Zargon earned a $0.50 million ARTC rebate in 2003 compared to a $0.32 million rebate in 2002. The SRC charges were $0.53 million in 2003, up from $0.52 million in the prior year and $0.34 million in 2001. North Dakota state taxes increased to $0.85 million Cdn in 2003 from $0.52 million in the prior year, reflecting increased production from Haas and the addition of the Truro Unit.

PRODUCTION EXPENSES

Zargon's production expenses increased 10 percent to $17.20 million in 2003 from $15.65 million in 2002; less than the 17 percent gain in 2003 production volumes. On a unit of production basis, production expenses decreased six percent to $6.33 per barrel of equivalent from $6.75 in 2002 ($5.89 in 2001) as the Company made a concerted effort to reverse an increasing cost trend.

Natural gas production expenses in 2003 rose three percent to $0.71 per thousand cubic feet from $0.69 per thousand cubic feet in 2002. The increase in the 2003 natural gas costs reflects the industry-wide trend to higher operating costs.

Oil production expenses in 2003 of $8.95 per barrel showed a reduction of eight percent from the prior year charge of $9.72 per barrel in 2002 ($8.85 per barrel in 2001). The corporate acquisition of Herc Oil Corp. in mid-2001 added largely long-life, low-decline exploitable oil properties with relatively high production costs. To contain these costs, a number of the smaller, less desirable oil properties were sold in 2002 and 2003, taking advantage of robust property markets. These dispositions of the higher cost components of our property base were the primary source of the 2003 oil production cost improvements.

OPERATING NETBACKS

The average oil price received after hedges in 2003 of $35.79 per barrel was five percent higher than $34.12 per barrel in 2002, while the average natural gas price received after hedges in 2003 of $6.13 per thousand cubic feet rose sharply, 55 percent above $3.95 per thousand cubic feet in 2002. Operating netbacks increased commensurately; oil and liquids netbacks rose 11 percent to $19.42 per barrel from $17.54 per barrel in 2002 and were helped by lower production costs. Natural gas netbacks increased 61 percent to $3.93 per thousand cubic feet from $2.44 per thousand cubic feet in 2002. On an equivalent basis, 2003 operating netbacks rose 36 percent to $21.73 from $15.99 in 2002.

OPERATING NETBACKS

	2003		2002	
	Oil and Liquids ($/bbl)	**Natural Gas ($/mcf)**	Oil and Liquids ($/bbl)	Natural Gas ($/mcf)
Production revenue	**36.66**	**6.33**	34.45	3.81
Hedging	**(0.87)**	**(0.20)**	(0.33)	0.14
Royalties	**(7.42)**	**(1.49)**	(6.86)	(0.82)
Production costs	**(8.95)**	**(0.71)**	(9.72)	(0.69)
Operating netbacks	**19.42**	**3.93**	17.54	2.44

GENERAL AND ADMINISTRATIVE EXPENSES

Gross general and administrative costs increased 17 percent in 2003 to $5.94 million from $5.06 million in 2002 due mainly to an increase in the number of employees and office space as the Company expanded. On a unit of production basis, general and administrative costs decreased 13 percent to $1.30 per barrel of equivalent. This improvement was derived from a 17 percent increase in production volumes and a 49 percent increase in capital program overhead recoveries pertaining to Zargon's 2003 expanded field exploration and operations program.

GENERAL AND ADMINISTRATIVE EXPENSES

($ million, except as noted)	**2003**	2002	2001
Gross general and administrative expense	**5.94**	5.06	4.50
Overhead recoveries	**(2.40)**	(1.61)	(1.42)
Net general and administrative expense	**3.54**	3.45	3.08
Net expense after recoveries ($/boe)	**1.30**	1.49	1.52
Number of office employees at year end	**34**	30	30

INTEREST EXPENSE

Zargon's primary borrowings are through its bank line of credit. Strong cash flows from operations throughout 2003 were sufficient to cover capital expenditures and, coupled with the proceeds from non-core dispositions, reduce bank indebtedness to $6.98 million at December 31, 2003. Short-term interest rates remained at historically low levels throughout the year. Interest charges for 2003 were $0.77 million, their lowest level since 1999. Zargon's effective interest rate was 4.5 percent on an average bank debt of $17.19 million in 2003 compared to 4.1 percent on an average bank debt of $26.72 million in 2002 and 4.9 percent on an average bank debt of $19.50 million in 2001. At year end 2003 Zargon's bank debt, net of working capital, totalled $13.09 million, down 54 percent from $28.74 million at December 31, 2002.

CAPITAL AND CURRENT INCOME TAX

Zargon did not pay current income taxes in 2003, but incurred $0.41 million of federal and provincial capital taxes compared to the $0.38 million incurred in 2002. Zargon reorganized its operations into a partnership structure effective July 10, 2001 and acquired significant excess tax pools with both the 2001 Herc Oil Corp. and 2002 Hadrian Energy Corp. acquisitions. These transactions helped increase the 2002 year-end tax pools to approximately $87 million and sheltered 2003 taxable income. Tax pools at December 31, 2003 were approximately $79 million and it is expected that they will shelter most of the budgeted 2004 taxable income.

CORPORATE NETBACKS

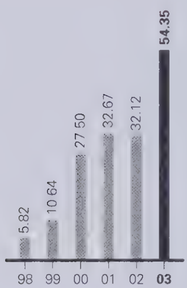
Historically high oil and natural gas commodity prices were experienced in 2003 and resulted in much higher revenue and operating netbacks. Driven by a 32 percent increase in revenue on a barrel of equivalent basis, cash flow netbacks increased 44 percent over the prior year to $20.00 per barrel of equivalent.

CORPORATE NETBACKS

($/boe)	2003	2002	2001
Petroleum and natural gas revenue	**37.40**	28.28	31.48
Hedging	**(1.06)**	0.29	(0.29)
Royalties	**(8.28)**	(5.83)	(7.01)
Production costs	**(6.33)**	(6.75)	(5.89)
Operating netbacks	**21.73**	15.99	18.29
General and administrative	**(1.30)**	(1.49)	(1.52)
Interest	**(0.28)**	(0.47)	(0.47)
Capital and current income taxes	**(0.15)**	(0.17)	(0.18)
Cash flow netbacks	**20.00**	13.86	16.12
Depletion and depreciation	**(6.99)**	(5.84)	(5.22)
Site restoration	**(0.58)**	(0.55)	(0.52)
Stock-based compensation	**(0.10)**	–	–
Unrealized foreign exchange	**0.11**	(0.03)	(0.05)
Future income taxes	**(3.41)**	(2.83)	(3.85)
Net earnings	**9.03**	4.61	6.48

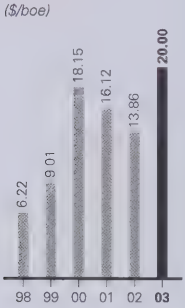
CASH FLOW FROM OPERATIONS

($ million)



CASH FLOW NETBACKS

($/boe)



CASH FLOW FROM OPERATIONS

In 2003, a 17 percent gain in production volumes, in addition to increases of six percent in oil and liquids prices and 66 percent in natural gas prices, produced a 69 percent gain in cash flow from operations to $54.35 million, compared to $32.12 million in 2002 and $32.67 million in 2001. The corresponding cash flow per diluted share was $2.96 in 2003 and was a 64 percent gain from $1.81 per diluted share in 2002 and compares to $2.03 in 2001. The per share statistics reflected a three percent increase in the average number of outstanding shares to 17.82 million in 2003 from 17.23 million in 2002.

DEPLETION AND DEPRECIATION

In 2003, Zargon's depletion and depreciation provision increased 40 percent to $19.01 million compared to $13.54 million in 2002 and $10.58 million in 2001. The higher charges reflect an increase of 17 percent in production volumes and a 20 percent increase in per unit charges. This large increase in per unit depletion and depreciation expense is primarily due to a December 31, 2003 year-over-year 14 percent reduction in the Company's proved reserves as calculated under the new policies of NI 51-101.

Depletion, depreciation and site restoration charges calculated on a unit of production method are based on total proved reserves with a conversion of six thousand cubic feet of natural gas being equivalent to one barrel of oil. The 2003 depletion calculation includes $4.73 million of future capital expenditures to develop the Company's reserves, but excludes $14.50 million of unproven properties relating to undeveloped land.

Zargon's depletion and depreciation, on a barrel of equivalent basis, increased 20 percent in 2003 to $6.99 from $5.84 in 2002 and $5.22 in 2001. Depletion and depreciation rates continue to climb as evidenced by Zargon's depletion and depreciation rate per barrel of equivalent in fourth quarter 2003 of $8.47 compared to a first half 2003 rate of $6.26.

SITE RESTORATION

Zargon provided for $1.57 million of site restoration charges in 2003 compared to $1.27 million in 2002 and $1.05 million in 2001. In fourth quarter 2003, Zargon increased the estimated future site restoration charges to $30,000 for each net working interest well from $25,000 per net well used in the past. The impact of this change and the year-over-year 14 percent reduction in proven reserves resulted in a fourth quarter charge of $0.78 per barrel of equivalent as compared to the first half 2003 rate of $0.50. In 2004 site restoration costs will be calculated using the new Asset Retirement Obligation rules as outlined under the "Recent Canadian Accounting Pronouncements" section.

STOCK-BASED COMPENSATION

Stock-based compensation of $0.26 million is recorded for the first time in the 2003 income statement in response to prospective adoption of a new CICA accounting standard. The non-cash expense was calculated using the Black-Scholes option-pricing model and covers all employee and director stock options granted by Zargon in 2003. The introduction of stock-based compensation expense added $0.10 per barrel of equivalent to the unit cost. These non-cash expenses will be recurring charges in future years if Zargon continues to grant employee and director stock options.

FUTURE INCOME TAXES

Zargon's 2003 future tax expense increased 42 percent to $9.28 million from $6.55 million in 2002, because of a 69 percent gain in cash flow from operations that was partially offset by a mid-year recognition of changes in federal tax legislation. The changes, which were

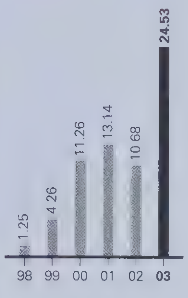
contained in Bill C-48 and introduced into the House of Commons in June 2003, will be implemented over a five-year period and encompass the following:

- The federal Large Corporations Tax of 0.225 percent will be eliminated;
- The corporate income tax rate on income from resource activities will be gradually reduced from 28 percent to 21 percent;
- The existing 25 percent resource allowance will be eliminated and a deduction for actual provincial and other Crown royalties paid will be introduced.

The effect of these one-time changes, which are considered to be "substantively enacted" for GAAP purposes, and a reduction in the Alberta corporate income tax rate from 13 percent to 12.5 percent, created a large one-time recovery in Zargon's future income tax expense of $4.31 million. On a barrel of equivalent basis, future income taxes were $3.41 in 2003, an increase of 20 percent from the prior year's future income taxes of $2.83. Without the tax rate adjustment, 2003 future taxes would have been approximately $13.59 million or $5.00 per barrel of equivalent. The 2003 effective tax rate (current and future) was 28 percent compared to 39 percent in 2002 and 38 percent in 2001.

NET EARNINGS

($ million)



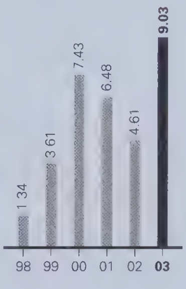
NET EARNINGS

Zargon's 2003 net earnings of $24.53 million jumped 130 percent from $10.68 million in 2002 and compare to $13.14 million recorded in 2001. The very strong 2003 increase was due primarily to the 69 percent increase in cash flow from operations and secondarily to the downward adjustment made in the 2003 future tax provision, which effectively added about $4.31 million to net earnings. On a per diluted share basis, 2003 net earnings increased 122 percent to $1.33 from $0.60 in 2002 and $0.82 in 2001.

On a barrel of equivalent basis, the 2003 net earnings were $9.03 compared to $4.61 in 2002 and $6.48 in 2001. Reflecting primarily the adjustment in future tax calculations, the 2003 net earnings represented 45 percent of cash flow, a strong gain from 33 percent of cash flow in 2002 and 40 percent in 2001.

NET EARNINGS NETBACKS

($/boe)



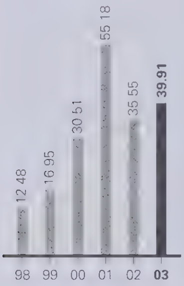
RETURN ON EQUITY

Zargon's pre-tax return on shareholders' equity in 2003 increased to 34 percent, compared to 22 percent in the previous year and 38 percent in 2001. The after-tax return on shareholders' equity in 2003 increased to 25 percent from 14 percent in the prior year (23 percent in 2001). Zargon's after-tax rates of return on equity have averaged 21 percent over the past three years and 18 percent over the Company's twelve-year corporate history.

CAPITAL EXPENDITURES

Net capital expenditures in 2003 of $39.91 million increased 12 percent over $35.55 million in 2002, although remained well below the $55.18 million expended in 2001, which included the relatively large Herc Oil Corp. acquisition. During the year, Zargon supported and internally funded an aggressive land acquisition program and a strong exploration effort. Total undeveloped land expenditures were $6.98 million, including $6.20 million of Crown land purchases at an average cost of $81 per acre, a significant increase in both amount and unit price from prior years and reflecting the very competitive current environment. Seismic work, drilling, completions and other field activities in 2003 were focused on gas exploration in the Alberta Plains and West Central Alberta core areas, plus a strong component of Williston Basin oil exploitation and totalled $30.32 million, a 56 percent increase from the prior year.

NET CAPITAL EXPENDITURES
($ million)



During 2003, Zargon made additional property acquisitions of $7.83 million and a series of dispositions aggregating $5.22 million for a net amount of property acquisitions of $2.61 million. The largest property acquisition in 2003 was the purchase of a 92.5 percent interest in the Truro Unit in North Dakota for $4.95 million Cdn The dispositions were opportunity-driven and were offered in packages of non-core, higher-cost property interests sold at premium prices. In 2004, Zargon is projecting to spend $45 million on capital expenditures.

CAPITAL EXPENDITURES

($ million)	2003	2002	2001
Undeveloped land	**6.98**	4.46	5.08
Geological and geophysical (seismic)	**5.69**	2.47	3.80
Drilling and completion of wells	**17.30**	12.49	17.44
Well equipment and facilities	**7.33**	4.48	4.87
Exploration and development	**37.30**	23.90	31.19
Property acquisitions	**7.83**	7.39	4.83
Property dispositions	**(5.22)**	(3.13)	(4.23)
Net property acquisitions	**2.61**	4.26	0.60
Corporate acquisitions assigned to property and equipment	**–**	7.39	23.39
Total net capital expenditures	**39.91**	35.55	55.18

LIQUIDITY AND CAPITAL RESOURCES

Zargon relies on three sources of funding to support its capital expenditure programs:

- Internally generated cash flow provides the basic level of funding for the Company's annual capital expenditures program.
- Debt may be utilized to expand capital programs when it is deemed appropriate. The Company has followed and intends to maintain a conservative debt policy.
- When debt is considered to be at reasonable upper levels, new equity, if available and if on favourable terms, will be utilized to expand capital programs further. Conversely, on occasions when Zargon's equity may be valued by the stock market at levels perceived to be at a substantial discount to the underlying net asset value, the Company will consider the repurchase of its shares through an issuer bid.

In 2003, Zargon's net capital expenditure program of $39.91 million was fully funded from cash flow from operations, while the remaining cash flow of $14.44 million was used to pay down debt.

CAPITAL SOURCES

($ million)	2003	2002	2001
Cash flow from operations	**54.35**	32.12	32.67
Changes in working capital and other	**2.66**	(3.58)	0.39
Change in bank indebtedness	**(18.30)**	1.14	8.23
Issuance of common shares	**1.20**	5.87	13.89
Total capital sources	**39.91**	35.55	55.18

CASH FLOW FROM OPERATIONS

It is anticipated that the majority, if not Zargon's entire 2004 capital budget, will be financed through the reinvestment of the Company's cash flow from operations. Cash flow is partially influenced by factors that the Company cannot control such as commodity prices, the US/Cdn dollar exchange rates and interest rates. Zargon's 2004 sensitivity to moderate fluctuations in these key business parameters is shown in the accompanying table.

CASH FLOW SENSITIVITY SUMMARY

	Change in 2004 Cash Flow	
	($ million)	($/share)
Change of $1.00 US/bbl in the price of WTI oil	1.40	0.07
Change in oil production of 100 bbl/d	0.60	0.03
Change of $0.10 US/mcf in the price of NYMEX natural gas	1.00	0.05
Change in natural gas production of one mmcf/d	1.30	0.07
Change in $0.01 in the $US/$Cdn exchange rate	1.20	0.06

BANK INDEBTEDNESS

The Company has authorized lines of credit totalling $50 million with a Canadian bank. At December 31, 2003, bank debt was $6.98 million, a decrease of 72 percent from the prior year-end amount of $25.28 million. Effective January 1, 2002 the Company adopted the CICA recommendation that treats revolving demand bank debt as a current liability.

Zargon's combined debt and working capital deficiency of $13.09 million at December 31, 2003 was equivalent to 24 percent of the 2003 cash flow from operations of $54.35 million and slightly less than the fourth quarter cash flow from operations of $13.24 million. At December 31, 2002 the combined debt and working capital deficiency was $28.74 million, equivalent to 89 percent of 2002 cash flow from operations.

EQUITY

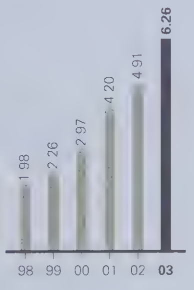
At year end 2003, Zargon had 17.99 million shares outstanding. Including the 1.30 million options outstanding (0.99 million vested at December 31, 2003) under the Company stock option plan, Zargon's fully diluted year-end balance of shares outstanding was 19.29 million.

Pursuant to the Company's stock option plan, Zargon issued 355 thousand shares for $1.20 million to employees and directors of the Company in 2003, at an average exercise price of $3.39 per share. In the prior year, 429 thousand shares were issued pursuant to the plan at an average exercise price of $2.94 per share.

On June 17, 2002 Zargon issued 542 thousand common shares as partial consideration for Hadrian Energy Corp. The shares issued were valued at $8.75 per share.

During 2003, 4.77 million Zargon shares traded on The Toronto Stock Exchange with a high of $13.75 per share, a low of $8.26 per share and a close of $13.50 per share. The 2003 trading statistics show a 25 percent year-over-year decrease in trading volume, and a 50 percent increase in the closing stock price. Zargon's market capitalization at year end 2003 was approximately $243 million.

SHAREHOLDERS' EQUITY
($/share)



SEGMENTED GEOGRAPHIC INFORMATION

In calendar 2003 and 2002, approximately 89 percent of Zargon's combined petroleum and natural gas revenue came from Western Canada properties (Alberta, Saskatchewan and Manitoba), with the remaining 11 percent of revenues generated in the United States (North Dakota and Montana).

CONTRACTUAL OBLIGATIONS

Zargon has certain contractual obligations relating to the lease of head office space, field operating leases and transportation contracts that extend over future years as set out in the table below:

CONTRACTUAL OBLIGATIONS

($ million)	Total	2004	2005	2006	Thereafter
Head office lease and other	2.15	0.62	0.60	0.59	0.34
Field operating leases	1.06	0.85	0.21	–	–
Transportation contracts	0.79	0.47	0.22	0.04	0.06
	4.00	1.94	1.03	0.63	0.40

CRITICAL ACCOUNTING POLICIES

The preparation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Company. The critical estimates are discussed below.

FULL COST ACCOUNTING

Zargon follows the full cost method of accounting for petroleum and natural gas operations as outlined in Canadian Institute of Chartered Accountants ("CICA") accounting guideline "Oil and Gas Accounting—Full Cost" (AcG-5). Under this accounting method, all costs related to the exploration and development of petroleum and natural gas reserves are capitalized. Capitalized costs, as well as the estimated future expenditures to develop proved reserves, are depleted using the unit of production method based on estimated proved petroleum and natural gas reserves.

PETROLEUM AND NATURAL GAS RESERVES

All of Zargon's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing or production levels.

CEILING TEST

In applying the full cost method, Zargon calculates a ceiling test on a quarterly basis to ensure that the net carrying value of petroleum and natural gas assets does not exceed the estimated undiscounted future net revenues from production of proved reserves before royalties, plus the cost of undeveloped properties, net of impairment, less amounts associated with future production costs, general and administrative, financing, site restoration and income tax costs. The calculation of future net revenue is based on sales prices, costs and regulations in effect at the period end.

RECENT CANADIAN ACCOUNTING PRONOUNCEMENTS

ASSET RETIREMENT OBLIGATIONS

In March 2003, the CICA approved Section 3110, "Asset Retirement Obligations," which requires liability recognition for retirement obligations associated with the Company's property, plant and equipment. The obligations are initially measured at fair value, which is the discounted future value of the liability. The fair value is capitalized as part of the cost of the related assets and amortized to expense over their useful lives. The liability accretes until the retirement obligations are settled. Section 3110 is effective for fiscal years beginning on or after January 1, 2004. The site restoration liability currently on the balance sheet, which has been calculated using the unit of production method, will be reversed on January 1, 2004. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

PETROLEUM AND NATURAL GAS ASSETS—FULL COST ACCOUNTING

In September 2003, the CICA issued Accounting Guideline 16, "Oil and Gas Accounting—Full Cost" (AcG-16), to replace AcG-5. The new guideline is effective for fiscal years beginning on or after January 1, 2004. The most significant change between AcG-16 and AcG-5 is that AcG-16 limits the carrying value of petroleum and natural gas properties to their fair value. The fair value is equal to estimated future cash flows from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate. This differs from the current cost recovery ceiling test under AcG-5 that uses undiscounted cash flows, constant prices and costs, less general and administrative and financing costs. Zargon is following AcG-5 at December 31, 2003. No write-down of the Company's petroleum and natural gas properties would be required under either method at December 31, 2003. AcG-16 also adopted the reserve evaluation and disclosure requirements of NI 51-101, which have been followed in the preparation of this report.

VARIABLE INTEREST ENTITIES

In June 2003, the CICA issued Accounting Guideline 15, "Consolidation of Variable Interest Entities" (AcG-15), which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004. Zargon has assessed that this new guideline is not applicable based on the current structure of the Company and therefore has no impact on the consolidated financial statements of the Company.

BUSINESS RISKS AND OUTLOOK

BUSINESS RISKS

Zargon's external business risks arise from the uncertainty of crude oil and natural gas pricing, the uncertainty of interest and exchange rates, environmental and safety issues, and financial and liquidity considerations. Additional risk arises from the production performance of existing properties, the changes in regulatory standards and the uncertain results from capital expenditure programs.

Zargon attempts to minimize pricing and currency exchange uncertainty with a risk management program that encompasses a variety of financial instruments. These include forward sales of oil and natural gas production, put options on both oil and natural gas, costless collars (in which some potential high price gain is given up in return for potential low price support) and US dollar currency hedges in different forms for up to 30 percent of its net oil and natural gas production volumes. In general the Company seeks to use strategies that allow minimum price expectations to be met while preserving most of the Company's

exposure to higher prices. This strategy is designed mainly to protect the Company against periods of unusually low commodity prices and by its nature is likely to produce significant hedging losses when prices are unusually high.

Environmental and safety risks are mitigated through compliance with provincial and federal environmental and safety regulations, by maintaining adequate insurance, and by adopting appropriate emergency response and employee safety procedures.

Financial and liquidity risks are reduced by limiting debt financing to conservative self-imposed debt to cash flow guidelines. Zargon actively manages the risks of its capital programs by concentrating drilling and subsequent development activities in areas where it has demonstrated proven technical capabilities and understanding. Finally, Zargon's capital budget is managed so as to limit capital exposure to any one project or concept to a non-material amount.

CORPORATE OUTLOOK

Zargon remains confident of its ability to maintain its record of consistent, sustainable and profitable growth. For calendar 2004, Zargon has budgeted $45 million of capital expenditures allocated to natural gas exploration, oil exploitation and property acquisition opportunities. In addition, its balance sheet strength will permit Zargon to make a relatively large property or corporate acquisition as value-added opportunities become available.

SELECTED QUARTERLY INFORMATION

				2003				2002
($ million, except per share amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas revenue	**24.51**	**23.76**	**24.20**	**29.19**	20.67	16.65	15.50	12.73
Cash flow from operations	**13.24**	**12.34**	**13.53**	**15.23**	10.71	7.75	7.47	6.19
Per diluted share ($)	**0.72**	**0.67**	**0.74**	**0.84**	0.59	0.43	0.42	0.36
Net earnings	**4.03**	**4.51**	**9.25**	**6.74**	4.28	2.27	2.55	1.58
Per diluted share ($)	**0.22**	**0.24**	**0.51**	**0.37**	0.24	0.13	0.14	0.09
Total assets	**175.07**	**166.89**	**160.05**	**159.34**	153.66	146.00	137.76	128.97
Bank indebtedness	**6.98**	**8.92**	**11.47**	**20.78**	25.28	28.71	28.00	25.26

Forward-Looking Statements: This document contains statements that are forward-looking, such as those relating to results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production and the magnitude of oil and natural gas reserves. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. The forward-looking statements contained in this annual report are as of March 23, 2004 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Zargon disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

MANAGEMENT'S REPORT

The consolidated financial statements of Zargon Oil & Gas Ltd. were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

Management has designed and maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of financial statements for reporting purposes. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgements made by management.

External auditors appointed by the shareholders have conducted an independent examination of the Company's accounting records in order to express their opinion on the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal control. The Board exercises this responsibility through its Audit Committee. The Audit Committee, which consists of non-management directors, has met with the external auditors and management in order to determine that management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Audit Committee has reported its findings to the Board of Directors who have approved the consolidated financial statements.

J.O. McCutcheon
Chairman

C.H. Hansen
President and Chief Executive Officer

Calgary, Canada
February 27, 2004

AUDITORS' REPORT

TO THE SHAREHOLDERS OF ZARGON OIL & GAS LTD.

We have audited the consolidated balance sheets of Zargon Oil & Gas Ltd. as at December 31, 2003 and 2002 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP
Chartered Accountants

Calgary, Canada
February 27, 2004

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ thousand)	2003	2002
ASSETS *[note 5]*		
Current		
Accounts receivable	**12,183**	11,942
Prepaid expenses and deposits	**980**	712
	13,163	12,654
Property and equipment *[note 4]*	**161,907**	141,006
	175,070	153,660
LIABILITIES		
Current		
Bank indebtedness *[note 5]*	**6,978**	25,279
Accounts payable and accrued liabilities	**19,277**	16,118
	26,255	41,397
Future site restoration	**6,026**	4,746
Future income taxes *[note 7]*	**30,200**	20,922
	62,481	67,065
Commitments and contingencies *[notes 9, 10 and 11]*		
SHAREHOLDERS' EQUITY		
Share capital *[note 6]*	**42,200**	40,997
Contributed surplus *[note 2]*	**264**	–
Retained earnings	**70,125**	45,598
	112,589	86,595
	175,070	153,660

See accompanying notes to the consolidated financial statements

On behalf of the Board:

J.O. McCutcheon
Director

C.H. Hansen
Director

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

For the years ended December 31 ($ thousand, except for per share amounts)	2003	2002
Revenue		
Petroleum and natural gas revenue	**101,657**	65,538
Hedging *[note 9]*	**(2,882)**	669
Royalties (net of Alberta Royalty Tax Credit)	**(22,508)**	(13,508)
	76,267	52,699
Expenses		
Production	**17,201**	15,649
General and administrative	**3,542**	3,455
Stock-based compensation *[note 2]*	**264**	–
Interest	**771**	1,100
Foreign exchange (gain) loss	**(297)**	86
Site restoration	**1,567**	1,268
Depletion and depreciation	**19,008**	13,536
	42,056	35,094
Earnings before income taxes	**34,211**	17,605
Income taxes *[note 7]*		
Future	**9,278**	6,548
Current	**406**	378
	9,684	6,926
Net earnings for the year	**24,527**	10,679
Retained earnings, beginning of year	**45,598**	34,919
Retained earnings, end of year	**70,125**	45,598
Earnings per common share *[note 8]*		
Basic	**1.38**	0.62
Diluted	**1.33**	0.60

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ thousand)	2003	2002
Operating activities		
Net earnings for the year	**24,527**	10,679
Add (deduct) non-cash items:		
Depletion and depreciation	**19,008**	13,536
Site restoration	**1,567**	1,268
Stock-based compensation *[note 2]*	**264**	–
Unrealized foreign exchange (gain) loss	**(297)**	86
Future income taxes	**9,278**	6,548
Cash flow from operations	**54,347**	32,117
Changes in non-cash working capital	**(936)**	(2,587)
	53,411	29,530
Financing activities		
Advances (repayment) of bank indebtedness	**(18,301)**	1,142
Exercise of stock options	**1,203**	1,262
	(17,098)	2,404
Investing activities		
Additions to property and equipment	**(45,124)**	(31,296)
Proceeds on disposal of property and equipment	**5,215**	3,134
Acquisition of Hadrian Energy Corp. (cash portion) *[note 3]*	**–**	(4,875)
Site restoration expenditures	**(287)**	(423)
Changes in non-cash working capital	**3,883**	1,325
	(36,313)	(32,135)
Decrease in cash	**–**	(201)
Cash, beginning of year	**–**	201
Cash, end of year	**–**	–

See accompanying notes to the consolidated financial statements

FOR THE YEARS ENDED DECEMBER 31, 2003 AND 2002

ALL AMOUNTS ARE STATED IN CANADIAN DOLLARS UNLESS OTHERWISE NOTED

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

DESCRIPTION OF BUSINESS

Zargon Oil & Gas Ltd. ("Zargon" or the "Company") is a public company that trades on the Toronto Stock Exchange and is incorporated under the Business Corporations Act (Alberta). The Company is engaged in the exploration, development and production of petroleum (crude oil, natural gas liquids) and natural gas in Canada and the United States ("US").

CONSOLIDATION

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the Company's accounting policies summarized below.

The consolidated financial statements include the accounts of Zargon Oil & Gas Ltd., all subsidiaries and a partnership. All subsidiaries and a partnership are directly or indirectly wholly owned and their operations are fully reflected in the consolidated financial statements.

REVENUE RECOGNITION

Petroleum and natural gas revenue is recognized in earnings when reserves are produced and delivered to the purchaser.

JOINT OPERATIONS

The majority of the oil and natural gas operations of the Company are conducted jointly with others and accordingly these financial statements reflect only the proportionate interests of the Company in such activities.

PROPERTY AND EQUIPMENT

The Company follows the full cost method of accounting for its oil and natural gas operations whereby all costs relating to the acquisition, exploration and development of oil and natural gas reserves are capitalized and accumulated in separate cost centres for Canada and the US. Such costs include land acquisition costs, annual carrying charges of non-producing properties, geological and geophysical costs, and costs of drilling and equipping wells.

Depletion and depreciation of petroleum and natural gas properties and equipment is computed using the unit of production method based on the estimated proved reserves of petroleum and natural gas before royalties determined by independent consultants. For purposes of this calculation reserves are converted to common units on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil. A portion of the cost of petroleum and natural gas rights relating to undeveloped properties is excluded from depletion calculations. Twenty percent of the year-end balance of these costs is added to the depletion base each year.

The Company applies a ceiling test to capitalized costs on a quarterly basis to ensure that such costs do not exceed the estimated undiscounted future net revenues from production of proved reserves before royalties, plus the cost of undeveloped properties, net of impairment, less amounts associated with future production costs, general and administrative, financing, site restoration and income tax costs. The calculation of future net revenue is based on sales prices, costs and regulations in effect at the period end. Proceeds on the disposal of petroleum and natural gas properties are applied against capitalized costs, with gains or losses not ordinarily recognized, unless such a disposal would result in a change in the depletion rate of 20 percent or more.

Depreciation of office equipment is provided using the declining balance method at an annual rate of 20 percent.

FUTURE SITE RESTORATION

Estimated future site restoration, including the removal of production facilities at the end of their useful lives, and net of salvage values, are provided for using the unit of production method. This estimate is based on current costs, existing legislation and industry standards. The annual charge is accounted for as an expense and the accumulated provision is reflected as a deferred liability. Actual site restoration costs are deducted from the accumulated provision in the year incurred.

FINANCIAL INSTRUMENTS

Derivative financial instruments are utilized to reduce commodity price risk associated with the Company's production of oil and natural gas. The base prices for the commodities are sometimes denominated in US dollars and the Company may also use such financial instruments to reduce the related foreign currency risk. Financial instruments may also be used from time to time to reduce interest rate risk on outstanding debt. The Company does not enter into financial instruments for trading or speculative purposes.

The Company follows a policy of using hedge instruments such as fixed price swaps, forward sales, puts, options and costless collars. The objective is to partially offset or mitigate the wide price swings commonly encountered in oil and natural gas commodities. The Company's policy is to designate each derivative financial instrument employed as a hedge of a specific portion of projected production over the term of the instrument. The Company formally documents its risk management objectives and strategies for undertaking the hedged transactions. This includes assessing the effectiveness of the derivative on an ongoing basis to ensure that the derivatives entered into are highly effective in offsetting changes in fair values of the hedged items. The instruments employed may be denominated in US or Canadian dollars. The Company believes the derivative financial instruments used are effective as hedges over their term. In the event that a designated hedge item is sold, extinguished, considered to become ineffective, or otherwise cancelled, any realized or unrealized gain or loss on such derivative commodity instruments is recognized in income. In times of particular price volatility such as the current year, the Company employs puts, options and costless collars as a preference if their cost is commercially acceptable so that most of the benefit of unforeseen high prices will continue to be available.

In the case of forward sales, the instrument can sometimes be satisfied by physical delivery. In all other cases the instrument is satisfied by payments or charges calculated by referring published prices to the agreed reference price in the terms and manner set out in the contract and paid or received monthly. In the case of physical delivery, the payment is part of the normal revenue stream and all other payments or charges are accounted for monthly as adjustments to revenue received.

Interest rate swap agreements are used from time to time to manage the floating interest rate on the Company's revolving bank debt. Such agreements involve the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. At December 31, 2003 and 2002 the Company had no such financial instruments.

Foreign currency swap agreements are used from time to time to manage the risk inherent in producing commodities whose price is based directly or indirectly on US dollars, using a notional principal equal to the projected monthly revenue from their sale. Payments or charges are calculated and paid according to the terms of the agreement, usually with monthly settlement. Foreign currency swap agreements are designated as hedges of revenue that is received in Canadian dollars, but whose amount is determined in foreign currency.

Gains or losses from these contracts, other than forward sales settled by physical delivery, are recognized as hedging gains or losses when realized.

INCOME TAXES

The Company follows the liability method of tax allocation in accounting for income taxes. Under this method, the Company records future income taxes for the effect of any differences between the accounting and income tax basis of an asset or liability using income tax rates expected to apply in the years in which these temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is recognized in net earnings in the period in which the change is substantively enacted.

FOREIGN CURRENCY TRANSLATION

The Company uses the temporal method of foreign currency translation whereby the monetary assets and liabilities recorded in a foreign currency are translated into Canadian dollars at year-end exchange rates, and non-monetary assets and liabilities at the exchange rates prevailing when the assets were acquired or liability incurred. Revenues and expenses are translated at the average rate of exchange for the year. Gains and losses on translation are included in the consolidated statements of earnings.

STOCK OPTIONS AND STOCK-BASED COMPENSATION

Under the Company's stock option plan, options to purchase common shares are granted to directors, officers and employees at current market prices. Options granted by the Company in 2003 are accounted for in accordance with the fair value method of accounting for stock-based compensation, and as such the cost of the option is charged to earnings with an offsetting amount recorded to contributed surplus, based on an estimate of the fair value using a Black-Scholes option-pricing model. No compensation expense has been recorded on options issued in 2002 (see note 6).

PER SHARE AMOUNTS

The Company follows the treasury stock method for the computation and disclosure of diluted per common share amounts. Under this method, the diluted weighted average number of common shares is calculated assuming that the proceeds from the exercise of dilutive options are used to purchase common shares at the average market price for the period.

MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation of property and equipment and the provision for future site restoration are based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of changes in such estimates in future periods could be material.

2. CHANGE IN ACCOUNTING POLICY

STOCK-BASED COMPENSATION

Effective January 1, 2003, the Company adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for stock-based compensation. As permitted by this new pronouncement, the Company prospectively adopted the fair-value method of accounting for stock options granted to employees and directors. Stock-based compensation is recorded in the consolidated statements of earnings as a separate expense for all options granted on or after January 1, 2003, with a corresponding increase recorded as contributed surplus. Compensation expense for options granted during 2003 is based on the estimated fair values at the time of the grant and the expense is recognized over the vesting period of the option. The Company recognized $264,000 of compensation expense for options granted during 2003 (see note 6 for further details). Upon the exercise of the stock options, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase in share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest; rather, the Company accounts for forfeitures as they occur.

In the event that vested options expire without being exercised, previously recognized compensation expense associated with such stock options is not reversed. For options granted prior to January 1, 2003, Zargon continues to disclose the pro forma earnings impact of related stock-based compensation expense as permitted by the new accounting pronouncement (see note 6).

3. ACQUISITION

On June 17, 2002, the Company acquired all of the outstanding shares of Hadrian Energy Corp. ("Hadrian"), a private oil and gas company, for consideration of $9.60 million. Consideration consisted of $4.745 million cash and the issuance of 542,340 Zargon common shares valued at $8.75 per share. Costs of $0.13 million were incurred to effect the transaction and were charged to share capital. The results of operations for Hadrian have been included in the consolidated financial statements since June 17, 2002. The acquisition was accounted for by the purchase method as follows:

($ thousand)	2002
Working capital	**(816)**
Property and equipment	**7,386**
Future income tax asset	**3,792**
Future site restoration	**(760)**
Total consideration	**9,602**

4. PROPERTY AND EQUIPMENT

	2003		
($ thousand)	**Cost**	**Accumulated Depletion and Depreciation**	**Net Book Value**
Petroleum and natural gas properties and equipment	**229,167**	**67,639**	**161,528**
Office equipment	**1,009**	**630**	**379**
	230,176	**68,269**	**161,907**

	2002		
($ thousand)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties and equipment	189,376	48,725	140,651
Office equipment	891	536	355
	190,267	49,261	141,006

At December 31, 2003, petroleum and natural gas properties and equipment include $14,498,000 (2002—$11,139,000) relating to undeveloped properties that have been excluded from the depletion calculation.

In 2003 the Company calculated its year-end ceiling test pertaining to the Canadian cost centre using the December monthly average field oil and liquids sale price of $35.79 per barrel and natural gas sales price of $6.01 per thousand cubic feet. The calculation pertaining to the US cost centre used the December monthly average field oil and liquids sale price of $34.67 per barrel and natural gas sales price of $5.21 per thousand cubic feet. No ceiling test write-down was required in either cost centre as a result of this test as at December 31, 2003. Additionally, had period end prices been used no ceiling test write-down would have been required.

5. BANK INDEBTEDNESS

The Company has a revolving demand credit facility that provides for a line of credit of $50,000,000 bearing interest at prime (December 31, 2003—4.5 percent; 2002—4.5 percent) and has pledged an assignment of accounts receivable, a first floating charge on all of the

Canadian assets and a fixed charge over certain property and equipment as collateral. The Company also has letters of credit outstanding in the amount of US $365,000 at December 31, 2003 (US $270,000 at December 31, 2002).

Through to June 2003 the Company also had a revolving demand credit facility in the United States for US $4,300,000 bearing interest at US prime plus 3/4 percent (December 31, 2002—5 percent) and had pledged a first floating charge on all of the US assets and a fixed charge over certain US property and equipment as collateral. As at December 31, 2002, bank indebtedness relating to US operations was $248,000 Cdn. This facility was cancelled during 2003.

6. SHARE CAPITAL

The Company is authorized to issue an unlimited number of common shares with no par value and an unlimited number of first preferred and second preferred shares.

COMMON SHARES

	2003		2002	
(thousand)	**Number of Shares**	**Amount $**	Number of Shares	Amount $
Shares issued				
Balance, beginning of year	**17,637**	**40,997**	16,666	35,066
Shares issued for Hadrian	**–**	**–**	542	4,669
Stock options exercised	**355**	**1,203**	429	1,262
Balance, end of year	**17,992**	**42,200**	17,637	40,997

On July 17, 2002 the Company issued 542,340 common shares as partial consideration for Hadrian Energy Corp. (note 3). The common shares issued were valued at $8.75 per share. Costs of $134,000 have been recorded net of tax of $57,000.

STOCK OPTIONS

The Company has a stock option plan available to employees and directors with grants under the Plan approved from time to time by the Board of Directors. Under the Plan, the Company is authorized to issue options to purchase, in aggregate, up to 10 percent of the issued and outstanding common shares. The options vest after one, two or three years and expire not more than five years from the date of grant. Each option can be exercised for one common share of the Company.

Stock options to acquire common shares are granted to employees and directors from time to time at exercise prices equal to the market value of the shares at the date of the grant.

The Company has reserved 1,476,000 shares at December 31, 2003 (December 31, 2002—1,431,000) for issuance under the stock option plan.

A summary of the status of the Company's stock option plan as at December 31, 2003 and 2002, and changes during the years ending on those dates is presented below:

	2003		2002	
	Shares (thousand)	**Weighted Average Exercise Price $**	Shares (thousand)	Weighted Average Exercise Price $
Outstanding at beginning of year	**1,215**	**5.10**	1,199	3.36
Granted	**459**	**9.50**	466	7.69
Exercised	**(355)**	**3.39**	(429)	2.94
Cancelled	**(22)**	**9.30**	(21)	7.37
Outstanding at end of year	**1,297**	**7.05**	1,215	5.10
Options exercisable at end of year	**985**	**6.25**	750	3.49

The following table summarizes information about stock options outstanding at December 31, 2003:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices $	Number Outstanding at 12/31/03 (thousand)	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price $	Number Exercisable at 12/31/03 (thousand)	Weighted Average Exercise Price $
2.60	175	0.3 years	2.60	175	2.60
4.05 to 5.40	260	2.2 years	4.80	260	4.80
7.20 to 7.45	342	3.0 years	7.43	342	7.43
8.28 to 9.05	83	3.2 years	8.96	77	8.95
9.30 to 11.74	437	4.1 years	9.51	131	9.33
	1,297		7.05	985	6.25

STOCK-BASED COMPENSATION

As discussed in note 2, the Company continues to disclose the pro forma effect of stock-based compensation on net earnings and earnings per basic and diluted common share. For purposes of these pro forma disclosures, the Company calculated the value of stock-based compensation using a Black-Scholes option-pricing model to estimate the fair value of stock options at the date of grant. The estimated fair value of options is amortized to expense over the options' vesting periods. For stock options granted in 2002, the Company's net earnings would be reduced by $215,000 for the year ended December 31, 2003 and by $654,000 for the year ended December 31, 2002. The 2002 stock option grants were allocated over a vesting period of one year while the 2003 grants vest over three years. Basic and diluted earnings per share figures would have been reduced by $0.01 and $0.01, respectively, for 2003 and by $0.04 and $0.04, respectively, for 2002.

The assumptions made for the options granted for 2003 include a volatility factor of expected market price of 21.92 percent, a weighted average risk-free interest rate of 3.90 percent, no dividend yield and a weighted average expected life of options of four years.

The assumptions made for the options granted for 2002 include a volatility factor of expected market price of 18.60 percent, a weighted average risk-free interest rate of 5.16 percent, no dividend yield and a weighted average expected life of options of four years.

7. INCOME TAXES

Income taxes differ from the amounts which would be obtained by applying statutory income tax rates to earnings before income taxes as follows:

($ thousand)	2003	2002
Statutory income tax rate	**41.58%**	42.61%
Computed income taxes	**14,225**	7,501
Add (deduct) income tax effect of:		
Non-deductible Crown charges, net of Alberta Royalty Tax Credit	**3,856**	2,884
Resource allowance	**(4,724)**	(3,467)
Rate adjustment	**(4,314)**	(162)
Large corporation and capital taxes	**406**	378
Other	**235**	(208)
	9,684	6,926

As at December 31, 2003, the Company has exploration and development costs, unamortized petroleum and natural gas property expenditures, undepreciated capital costs, unamortized share issue costs and non-capital loss carry forwards available for deduction against future taxable earnings in aggregate of approximately $78,780,000 (December 31, 2002—$86,893,000).

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of the Company's net future income tax liability are as follows:

($ thousand)	2003	2002
Net book value of property and equipment in excess of tax pools	**19,501**	16,982
Deferred partnership earnings*	**13,637**	9,816
Future site restoration	**(2,144)**	(1,529)
Non-capital loss carry forwards expiring by 2008	**(395)**	(4,062)
Share issue costs	**(240)**	(242)
Provincial rebate	**(159)**	(43)
	30,200	20,922

** The Company's current organizational structure includes a partnership arrangement, which by its nature defers taxable earnings to a future taxation year.*

8. WEIGHTED AVERAGE NUMBER OF COMMON SHARES

(thousand)	2003	2002
Weighted average number of common shares outstanding during the year	**17,824**	17,233
Diluted weighted average number of common shares outstanding during the year	**18,373**	17,795

Shares of 549,042 (2002—561,999) were added to the weighted average number of common shares outstanding during the year in the calculation of diluted per common share amounts. These share additions represent the dilutive effect of stock options according to the treasury stock method. Adjustments to the numerator amounts were not required in such calculations.

9. FINANCIAL INSTRUMENTS

FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

Financial instruments of the Company consist of accounts receivable, accounts payable, and bank indebtedness. As at December 31, 2003 and 2002, there are no significant differences between the carrying values of these amounts and their estimated market values.

CREDIT RISK MANAGEMENT

Accounts receivable include amounts receivable for petroleum and natural gas sales that are generally made to large credit-worthy purchasers, and amounts receivable from joint venture partners that are recoverable from production. Accordingly, the Company views credit risks on these amounts as low.

The Company is exposed to losses in the event of non-performance by counterparties to hedge transactions.The Company minimizes credit risk associated with possible non-performance to these financial instruments by entering into contracts with only highly rated counterparties, limits on exposures to any one counterparty, and monitoring procedures. The Company believes these risks are minimal.

INTEREST RATE RISK MANAGEMENT

Borrowings under bank credit facilities are for short periods and are market-rate-based (variable interest rates); thus carrying values approximate fair values.

FOREIGN CURRENCY RISK MANAGEMENT

The Company is exposed to fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil and to a large extent natural gas prices are based upon reference prices denominated in US dollars, while the majority of the Company's expenses are denominated in Canadian dollars. When appropriate, the Company enters into agreements to fix the exchange rate of Canadian dollars to US dollars in order to manage the risk (see table below).

COMMODITY PRICE RISK MANAGEMENT

The Company enters into hedge transactions on oil and natural gas. The agreements entered into are forward transactions providing the Company with a range of fixed prices on the commodities sold.

The Company has outstanding contracts at December 31, 2003 and 2002 as follows:

At December 31, 2003

	Volume	Rate	Price	Range of Terms
Oil swaps	36,400 bbl	200 bbl/d	$26.44 US/bbl	Jan. 1/04–Jun. 30/04
	36,800 bbl	200 bbl/d	$27.10 US/bbl	Jul. 1/04–Dec. 31/04
Oil collars	36,400 bbl	200 bbl/d	$22.50 US/bbl Put $26.85 US/bbl Call	Jan. 1/04–Jun. 30/04
	36,400 bbl	200 bbl/d	$24.00 US/bbl Put $27.65 US/bbl Call	Jan. 1/04–Jun. 30/04
	36,800 bbl	200 bbl/d	$24.00 US/bbl Put $27.80 US/bbl Call	Jul. 1/04–Dec. 31/04
Natural gas swaps	364,000 gj	4,000 gj/d	$7.21/gj	Jan. 1/04–Mar. 31/04
	856,000 gj	4,000 gj/d	$5.15/gj	Apr. 1/04–Oct. 31/04
Natural gas collars	91,000 gj	1,000 gj/d	$5.50/gj Put $7.90/gj Call	Jan. 1/04–Mar. 31/04
	428,000 gj	2,000 gj/d	$5.00/gj Put $6.85/gj Call	Apr. 1/04–Oct. 31/04
Natural gas put	273,000 gj	3,000 gj/d	$5.00/gj	Jan. 1/04–Mar. 31/04

At December 31, 2002

	Volume	Rate	Price	Range of Terms
Oil swaps	36,800 bbl	200 bbl/d	$24.80 US/bbl	Jul. 1/03–Dec. 31/03
	36,200 bbl	200 bbl/d	$23.60 US/bbl	Jan. 1/03–Jun. 30/03
	146,000 bbl	400 bbl/d	$23.98 US/bbl	Jan. 1/03–Dec. 31/03
Natural gas swaps	360,000 gj	4,000 gj/d	$3.85/gj	Jan. 1/03–Mar. 31/03
	428,000 gj	2,000 gj/d	$4.85/gj	Apr. 1/03–Oct. 31/03
Natural gas collars	360,000 gj	4,000 gj/d	$3.85/gj Put $8.05/gj Call	Jan. 1/03–Mar. 31/03
	428,000 gj	2,000 gj/d	$4.00/gj Put $6.10/gj Call	Apr. 1/03–Oct. 31/03
Currency collar	$1,000,000 Cdn	–	$1.56 Put $1.62 Call	Jan. 1/03–Dec. 31/03

At December 31, 2003, the cost to settle the above contracts would have been $894,000, and as at December 31, 2002, the cost to settle the above contracts would have been $2,867,000. These instruments have no book values recorded in the consolidated financial statements.

10. COMMITMENTS

The Company is committed to future minimum payments for natural gas transportation contracts in addition to operating leases for office space, office equipment, vehicles and field equipment. Payments required under these commitments for each of the next four years are: 2004—$1,940,000; 2005—$1,032,000; 2006—$623,000; 2007—$365,000; and thereafter $38,000.

11. CONTINGENCIES

The Company indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their service to the Company to the extent permitted by law. The Company has acquired and maintains liability insurance for its directors and officers. The Company is party to various legal claims associated with the ordinary conduct of business. The Company does not anticipate that these claims will have a material impact on the Company's financial position.

12. SUPPLEMENTAL CASH FLOW INFORMATION

($ thousand)	2003	2002
Cash interest paid	**714**	1,150
Cash taxes paid	**360**	378

13. SEGMENTED INFORMATION

The Company's entire operating activities are related to exploration, development and production of oil and natural gas in the geographic segments of Canada and the US.

	2003		
($ thousand)	**Canada**	**United States**	**Combined**
Petroleum and natural gas revenue	**90,034**	**11,623**	**101,657**
Property and equipment	**139,900**	**22,007**	**161,907**
Total assets	**152,061**	**23,009**	**175,070**
Net capital expenditures	**33,373**	**6,536**	**39,909**

	2002		
($ thousand)	Canada	United States	Combined
Petroleum and natural gas revenue	58,360	7,178	65,538
Property and equipment	123,761	17,245	141,006
Total assets*	135,570	18,090	153,660
Net capital expenditures**	33,603	1,945	35,548

** Total asset amounts from prior year have been reclassified in part from Canada to the US for consistency with the current year presentation.*

*** Includes property from corporate acquisition.*

14. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform with the current year's financial statement presentation.

TWELVE-YEAR FINANCIAL AND OPERATING SUMMARY

	2003	2002	2001
FINANCIAL ($ thousand, except for per share amounts)			
Petroleum and natural gas revenue	**101,657**	65,538	63,795
Less expenses—cash items			
Royalties (net of Alberta Royalty Tax Credit)	**22,508**	13,508	14,222
Production	**17,201**	15,649	11,933
General and administrative (net)	**3,542**	3,455	3,083
Hedging	**2,882**	(669)	573
Interest	**771**	1,100	957
Current and capital taxes	**406**	378	358
Cash flow from operations	**54,347**	32,117	32,669
Less expenses—non-cash items			
Depletion, depreciation and foreign exchange	**18,711**	13,622	10,683
Future income tax	**9,278**	6,548	7,806
Site restoration	**1,567**	1,268	1,045
Stock-based compensation	**264**	–	–
Net earnings	**24,527**	10,679	13,135
Per share, diluted			
Cash flow ($/share)	**2.96**	1.81	2.03
Net earnings ($/share)	**1.33**	0.60	0.82
Net capital expenditures	**39,909**	35,548	55,176
Balance sheet at year end			
Property and equipment, net	**161,907**	141,006	118,994
Bank and other debt	**6,978**	25,279	24,137
Shareholders' equity	**112,589**	86,595	69,985
Shareholders' equity ($/share)	**6.26**	4.91	4.20
Weighted average common shares outstanding (thousand)	**17,824**	17,233	15,558
Year-end common shares outstanding (thousand)	**17,992**	17,637	16,666
OPERATIONS			
Total production (boe/d)	**7,446**	6,349	5,553
Oil and liquids (bbl/d)	**3,287**	2,968	2,441
Natural gas (mmcf/d)	**24.95**	20.29	18.67
Equivalent per million shares (boe/d)	**418**	368	357
Total proved reserves (mboe)	**18,859**	21,870	20,605
Proved oil and liquids (mbbl)	**10,505**	11,114	10,482
Proved natural gas (bcf)	**50.13**	64.54	60.74
Total proved and probable reserves (mboe) [1]	**24,994**	24,313	23,199
Proved and probable oil and liquids (mbbl) [1]	**13,566**	12,445	11,948
Proved and probable natural gas (bcf) [1]	**68.58**	71.21	67.51
Equivalent per share—year end (boe) [1]	**1.39**	1.38	1.39
Average selling prices (before hedges)			
WTI crude oil price ($US/bbl)	**31.04**	26.08	25.90
FOB Edmonton crude oil price ($/bbl)	**43.14**	39.94	39.18
Zargon field oil price ($/bbl)	**36.66**	34.45	31.86
NYMEX Henry Hub Price ($US/mmbtu)	**5.49**	3.35	3.94
Alberta AECO natural gas price ($/mmbtu)	**6.70**	4.18	5.43
Zargon field natural gas price ($/mcf)	**6.33**	3.81	5.19
Other Data			
Wells drilled, net	**38.6**	31.6	47.7
Undeveloped land (thousand net acres)	**398.4**	331.3	240.7
Closing share price ($/share)	**13.50**	9.00	7.20

1 *In this table the established reserves (proved plus 50 percent probable) for the prior years (1992–2002) are used as a comparison to the December 31, 2003 proved and probable reserves. This adjustment is necessary due to the change in reserve risk assessments required to comply with new NI 51-101 reserve guidelines.*

2000	1999	1998	1997	1996	1995	1994	1993	1992
53,306	24,048	14,264	16,800	12,150	8,244	5,748	4,016	2,130
10,716	4,033	1,837	2,652	2,075	1,293	997	751	529
8,615	6,120	5,080	5,081	3,324	2,875	2,095	1,474	658
2,189	1,463	1,252	1,035	741	508	416	277	205
2,733	1,095	(180)	44	434	–	–	–	–
1,269	592	377	142	232	313	122	196	134
288	103	77	181	236	–	–	(39)	59
27,496	10,642	5,821	7,665	5,108	3,255	2,118	1,357	545
6,801	4,750	3,659	3,276	2,028	1,733	1,180	830	382
8,713	1,046	430	1,421	910	507	21	40	5
720	585	482	490	267	215	194	128	21
–	–	–	–	–	–	–	–	–
11,262	4,261	1,250	2,478	1,903	800	723	359	137
1.86	0.70	0.43	0.62	0.51	0.37	0.28	0.25	0.16
0.76	0.29	0.10	0.20	0.19	0.10	0.09	0.08	0.05
30,514	16,945	12,477	13,371	7,821	5,526	4,730	6,017	1,972
74,394	50,383	38,189	29,371	20,776	14,983	11,604	8,146	3,021
15,902	14,116	6,178	4,872	491	2,864	2,040	400	1,393
42,522	32,523	29,320	22,364	18,060	11,127	9,048	7,696	1,575
2.97	2.26	1.98	1.80	1.54	1.20	1.12	1.02	0.61
14,408	14,686	13,025	12,051	9,659	8,441	7,595	5,781	4,050
14,315	14,420	14,810	12,553	10,486	9,261	8,061	7,510	4,050

4,140	3,236	2,563	2,445	1,629	1,347	993	771	362
1,725	1,711	1,508	1,385	1,012	885	616	426	256
14.49	9.15	6.33	6.36	3.70	2.77	2.26	2.07	0.63
287	224	196	203	169	159	131	133	89
16,200	12,387	9,736	7,811	5,903	4,213	3,499	2,743	1,000
6,340	5,210	5,072	4,134	3,706	2,744	2,099	1,371	720
59.16	43.06	27.99	22.06	13.18	8.82	8.40	8.23	1.68
18,728	14,310	11,339	8,950	7,193	5,404	4,693	3,743	1,253
7,508	6,150	6,028	4,917	4,217	3,365	2,838	2,007	863
67.28	48.96	31.87	24.20	17.86	12.24	11.13	10.75	2.34
1.31	0.99	0.77	0.71	0.69	0.58	0.58	0.50	0.31
30.20	19.24	14.42	20.61	22.01	18.40	17.17	18.48	20.55
44.33	27.35	20.08	27.64	29.23	24.04	21.86	21.90	23.52
40.73	25.02	17.80	24.70	26.91	21.79	19.41	18.53	20.25
4.31	2.27	2.09	2.48	2.72	1.69	1.92	2.12	–
5.60	2.92	2.07	1.80	1.47	1.19	1.96	1.93	1.36
5.20	2.52	1.93	1.86	1.62	1.19	1.67	1.49	0.93
38.6	18.8	4.9	14.6	8.5	6.5	6.9	0.1	–
213.1	177.2	115.8	81.4	63.5	44.5	23.6	18.1	9.5
4.45	3.00	2.40	3.40	2.32	1.80	1.07	1.10	–

BOARD OF DIRECTORS

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Calgary, Alberta

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Oakville, Ontario

H. Earl Joudrie (3)
Toronto, Ontario

Kyle D. Kitagawa (1)
Calgary, Alberta

John O. McCutcheon
Vancouver, British Columbia

James D. Peplinski (2)(4)
Calgary, Alberta

Byron J. Seaman (1)
Calgary, Alberta

J. Graham Weir (1)(4)
Calgary, Alberta

William J. Whelan (1)(2)
Calgary, Alberta

Grant A. Zawalsky (3)(4)
Calgary, Alberta

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Chairman

Craig H. Hansen
President and Chief Executive Officer

Mark I. Lake
Vice President, Exploration

Daniel A. Roulston
Vice President, Operations

Sheila A. Wares
Vice President, Accounting

Kenneth W. Young
Vice President, Land

1 Audit Committee
2 Compensation Committee
3 Governance Committee
4 Reserves Committee

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
Trading Symbol: ZAR

TRANSFER AGENT

Valiant Trust Company
510, 550-6th Avenue S.W.
Calgary, Alberta T2P 0S2

BANKER

The Toronto-Dominion Bank
2 Calgary Place, 340-5th Avenue S.W.
Calgary, Alberta T2P 2P6

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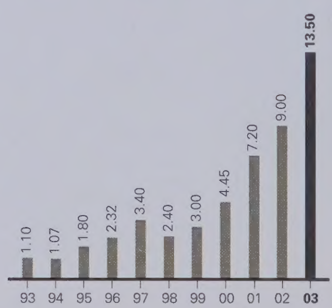
Website: www.zargon.ca

ZARGON YEAR-END SHARE PRICE



ANNUAL MEETING

The Annual General and Special Meeting of Shareholders will be held on Monday, May 17, 2004 at 2:00 p.m. at the Metropolitan Centre, Strand/Tivoli Room, 333–4th Avenue S.W. Calgary, Alberta. Shareholders are encouraged to attend.

bbl	Barrel
bbl/d	Barrels of oil per day
bcf	Billion cubic feet
boe	Barrel of oil equivalent (6 mcf is equivalent to 1 bbl)
boe/d	Barrel of oil equivalent per day
btu	British thermal units
FD&A	Finding, development and acquisition
gj	Gigajoule
m	Thousand
mm	Million
mcf	Thousand cubic feet
mcf/d	Thousand cubic feet per day
PV	Present value
PVBT	Present value before tax

FORWARD-LOOKING STATEMENTS

This document contains statements that are forward-looking, such as those relating to results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production and the magnitude of oil and natural gas reserves. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. The forward-looking statements contained in this annual report are as of March 23, 2004 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Zargon disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Designed and Produced by Karo

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